

TECHNICAL REVIEW DOCUMENT
For
RENEWAL / MODIFICATION of OPERATING PERMIT 96OPPB133

Public Service Company – Comanche Station
Pueblo County
Source ID 1010003

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April – June 2011

Revised November 2011 and January 2012

Revised April 2012 to reflect the certification of the mercury continuous emission monitoring systems and the cancellation of the Title V permit for Boral Comanche (03OPPB241)

I. Purpose:

This document establishes the basis for decisions made regarding the applicable requirements, emission factors, monitoring plan and compliance status of emission units covered by the renewal and modification of the Operating Permit for Public Service Company's (PSCo's) Comanche Station. The original Operating Permit was issued June 1, 2002. The expiration date for the permit was June 1, 2007. However, since a timely and complete renewal application was submitted, under Colorado Regulation No. 3, Part C, Section IV.C all of the terms and conditions of the existing permit shall not expire until the renewal Operating Permit is issued and any previously extended permit shield continues in full force and operation. The source submitted a renewal application on April 27, 2006. Following the submittal of the renewal application, the source submitted an application for a significant modification on September 7, 2010 in order to incorporate the provisions of the Comanche Unit 3 project into the Title V permit. The significant modification and renewal are being processed concurrently.

This document is designed for reference during the review of the proposed permit by the EPA, the public, and other interested parties. The conclusions made in this report are based on information provided in the renewal application submitted on April 27, 2006, the significant modification submitted on September 7, 2010, additional information submitted on April 29, May 25, and August 9, 2011, comments on the draft permit and technical review document received on January 13, 2012, previous inspection reports and various e-mail correspondence, as well as telephone conversations with the applicant. Please note that copies of the Technical Review Document for the original permit and any Technical Review Documents associated with subsequent modifications of the original Operating Permit may be found in the Division files as well as on the Division website at <http://www.cdphe.state.co.us/ap/Titlev.html>. This narrative is intended only as an adjunct for the reviewer and has no legal standing.

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this Operating Permit application have been

reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This Operating Permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this Operating Permit without applying for a revision to this permit or for an additional or revised construction permit.

II. Description of Source

The facility consists of three (3) coal fired boilers used to generate electricity. All three boilers are pulverized coal-fired units. Unit 1 (boiler 1) is a 350 MW (net output) tangentially fired boiler. Unit 2 (boiler 2) is a 350 MW (net output) wall-fired boiler and Unit 3 (boiler 3) is a 783 MW (net output) supercritical, tangentially fired boiler. Units 1 and 2 are equipped with dual-fuel natural gas and No. 2 fuel oil ignitors and natural gas burners but No. 2 fuel oil is no longer fired in the ignitors (the oil delivery system has been disconnected). Natural gas is used in Unit 3 for startup, shutdown and flame stabilization.

The facility originally consisted of Units 1 and 2 and the necessary support equipment for these units (coal and ash handling equipment and cooling and service water towers). In August of 2004 PSCo submitted an application to construct a new coal-fired boiler, Unit 3. In the August 2004 application PSCo proposed to install NO_x controls (low NO_x burners with over-fire air) on both Units 1 and 2 and SO₂ controls (lime spray dryer) on Unit 2 order to “net-out” of PSD review for NO_x and SO₂. In December of 2004, PSCo entered into a Settlement Agreement, with several citizen groups in order to expedite issuance of the construction permit for Unit 3. As part of this Settlement Agreement, PSCo agreed to install SO₂ controls on Unit 1, as well as Unit 2. Units 1 and 2 are equipped with baghouses to control particulate matter (PM) emissions, low NO_x burners and over-fire air to control NO_x emissions and lime spray dryers to control SO₂ emissions. Unit 3 is equipped with a baghouse to control PM emissions, low NO_x burners, over-fire air and selective catalytic reduction (SCR) to control NO_x emissions, a lime spray dryer to control SO₂ emissions and sorbent injection to control mercury (Hg) emissions. Although not included in the construction permits issued for the Unit 3 project, the Settlement Agreement specified that following startup of Unit 3, PSCo shall test various Hg control technologies on Units 1 and 2 for a period of one year and within two years of startup of Unit 3, PSCo shall comply with plantwide mercury limit. On May 25, 2011, PSCo submitted an application for the plantwide Hg limit, which will take effect on January 1, 2012. In order to comply with the plant wide limit, sorbent injection will be utilized on Units 1 and 2 to control Hg emissions.

In addition to the boilers, emission units and/or activities that have been included in the Section II of the permit include: cooling water and service water towers, coal and ash handling equipment, haul roads (vehicle traffic on paved and unpaved roads), lime silos and slakers, recycle ash silos and mixers, sorbent silos and a diesel fired emergency generator.

Boral Material Technologies, Inc. (BMTI) previously conducted ash conditioning, handling and blending operations at Comanche station. BMTI was considered a support facility for PSCo's Comanche Station and as such was considered a single source with PSCo's Comanche Station. The BMTI equipment has not been operated for years and on April 4, 2012 BMTI requested that the Title V permit, underlying construction permit and air pollution emission notices (APENs) be cancelled for their facility. Although BMTI still hauls ash for PSCo at Comanche Station, these activities are addressed in the PSCo's Title V permit.

The facility is located south and east of Pueblo at 2005 Lime Road, in Pueblo County. The area in which the plant operates is designated as attainment for all criteria pollutants.

There are no affected states within 50 miles of the plant. The Great Sand Dunes National Wilderness Area, a Federal Class I designated area, is within 100 kilometers of the plant. The Great Sand Dunes National Monument, those portions not included as National Wilderness Areas, is federal land within 100 kilometers of the facility. This area has been designated by the State to have the same sulfur dioxide increment as federal Class I designated areas.

The summary of emissions that was presented in the Technical Review Document (TRD) for the original permit issuance has been revised to address the new equipment and modifications to existing units that were part of the Unit 3 project. Emissions (in tons/yr) at the facility are as follows:

Emission Unit	PM	PM ₁₀	SO ₂	NO _x	CO	VOC	Pb ¹	HAPS
Unit 1	1,546.0	1,423.0	1,855.9	3,093.2	487.3	60.4	0.16	See Page 56
Unit 2	1,525.0	1,403.0	1,830.1	3,050.2	528.3	59.9	0.16	
Unit 3	715.0	650.0	3,250.0	2,600.0	4,225.0	114.0	0.07	
Units 1 & 2 cooling/service water towers	12.0	12.0				4.40		
Unit 3 cooling water tower	9.25	2.22				1.95		
Unit 1 coal handling system	1.88	0.56						
Unit 2 coal handling system	1.90	0.58						
Unit 3 coal handling system	14.09	13.80						
Coal handling – fugitive	25.2	6.60						
Recycle ash silos (6)	7.03	7.03						
Recycle ash mixers (6)	2.58	2.58						
Lime silos (2)	0.15	0.15						

Emission Unit	PM	PM ₁₀	SO ₂	NO _x	CO	VOC	Pb ¹	HAPS
Lime slakers (3)	1.20	1.20						See Page 56
Sorbent silos (4)	0.76	0.76						
Unit 1 waste ash silo	0.047	0.041						
Unit 2 waste ash silo	0.045	0.039						
Unit 3 waste ash silo	0.097	0.084						
Ash landfill – fugitive	7.25	2.45						
Haul roads	17.3	4.48						
Emergency Generator	0.1	0.1	0.1	4.2	1.7	0.11		
Total Emissions	3,886.88	3,530.67	6,936.1	8,747.6	5,242.3	240.76	0.39	94.22

¹Lead (Pb) emissions for Unit 3 are from the Unit 3 construction permit application (based on EPRI emission factor, coal data and the proposed PM BACT limit of 0.0150 lb/MMBtu), since the construction permit issued for Unit 3 set a lower PM BACT limit, this estimate is slightly high. Pb emissions from Units 1 and 2 are based on the same methodology used for Unit 3 (EPRI emission factor, coal data and the Reg 1 PM limit of 0.10 lb/MMBtu).

Potential to emit used in the above table are based on the following information:

Criteria Pollutants

Potential to emit for all emission units except for the Unit 1 waste ash silo and the Unit 1 coal handling system are based on permitted emissions. Note that for the emergency generator only the NO_x emission limitation is included in the permit. Estimated emissions from the emergency generator for other pollutants are based on the emission factors identified in this document and the permitted fuel consumption limit. Emissions from the Unit 1 waste ash silo and coal handling system are based on the emission calculation methodologies specified in this document and the maximum estimated throughput rate for the unit (based on design rate and 8760 hrs/yr of operation).

Hazardous Air Pollutants (HAP)

The potential to emit on page 56 provides total HAPS for each unit at the facility. The breakdown of HAP emissions by individual HAP and emission unit is provided on page 56 of this document. HAP emissions, as shown in the table on page 56, are based on the following information:

Units 1 and 2: Except for lead, metal HAP emissions from Units 1 and 2 are based on AP-42 emission factors (Section 1.1, dated 9/98, Table 1.1-18) and the permitted coal consumption limit. For lead, emissions are based on the method used for Unit 3 (Electric Power Research Institute (EPRI) emission factors, coal data and the Reg 1 PM limit of 0.10 lb/MMBtu). Organic HAP emissions are based on emission factors from the

EPRI Emission Factor Handbook, unit design rate (in MMBtu/hr) and 8760 hrs/yr of operation. Mercury emissions are based on 2009 emissions reported as required by the Settlement Agreement. HF and HCl emissions from the boilers are based on the maximum emission factor, in units of lb/ton, determined from reported HF and HCl emissions and coal consumption on recent APENS (2009 and 2010 data) and the permitted coal consumption limit. Chloroform emissions from the Units 1 and 2 cooling and service water towers are based on permitted VOC emissions.

Unit 3: Metal HAP emissions from Unit 3 are based on the estimates provided in the Unit 3 construction permit application. (Emissions based on the EPRI emission factor handbook, coal composition data and the proposed PM BACT limit of 0.0150 lb/MMBtu. Selenium emissions based on EPRI LARK-TRIPP R2003.) Organic HAP emissions are based on emission factors from the EPRI Emission Factor Handbook, unit design rate (in MMBtu/hr) and 8760 hrs/yr of operation. HF emissions are based on the permitted annual emission limit. HCl emissions are based on the 112(g) limit (6.2×10^{-4} lb/MMBtu), unit design rate (in MMBtu/hr) and 8760 hrs/yr of operation. Mercury emissions are based on the 112(g) limit (14.7×10^{-6} lb/MW_{hr}), unit design rate (in gross MW, which is 848 MW) and 8760 hrs/yr of operation.

Note that actual emissions are typically less than potential emissions and actual emissions are shown on page 57 of this document.

Compliance Assurance Monitoring (CAM) Requirements

The source addressed the applicability of the CAM requirements for the facility prior to the addition of Unit 3 in their renewal application and CAM is discussed further in this document under Section III – Discussion of Modifications Made, under “Source Requested Modifications”.

MACT Requirements

The facility is a major source for HAP emissions. As such the facility is subject to the following requirements:

Coal and Oil-Fired Electric Utility Steam Generating Units (40 CFR Part 63 Subpart UUUUU)

EPA has proposed requirements for coal and oil-fired electric utility steam generating units (published in the Federal Register on May 3, 2011) and these requirements will apply to Units 1, 2 and 3 at this facility. Under the proposed rule, all three units are considered “existing” and will be subject to emission limitations for PM, HCl and Hg. The rule provides alternative options to the PM limit (either total or individual non-Hg metal HAP limits) and HCl limits (SO₂ limits).

EPA signed the final MACT requirements for electric utility steam generating units on December 16, 2011. The final rule is fairly similar to the proposed rule with emissions

limitations for PM, HCl and Hg and several options for each pollutant, including provisions for low emitting units and emissions averaging for units within the same subcategory, located at a single source. Given the number of compliance options and the fact that existing sources will have three years to comply with the requirements, the permit includes a requirement to submit an application to modify their Title V permit within one year of the compliance date to incorporate the chosen compliance options into the permit.

Note that on February 22, 2010 a revised construction permit was issued for Unit 3 to incorporate a case-by-case 112(g) MACT analysis. There are provisions under the 112(g) requirements (40 CFR Part 63 Subpart B §§ 63.40 – 63.44) regarding subsequent MACT standards promulgated after a 112(g) determination has been issued. These provisions include retaining 112(g) requirements if they are more stringent than the subsequently published MACT standard and setting compliance dates for sources with 112(g) determinations. These requirements are included in the permit.

RICE MACT (40 CFR Part 63 Subpart ZZZZ)

The Comanche facility has one new emergency generator which was permitted as part of the Unit 3 project (commenced operation July 2009) and the current Title V permit lists an emergency diesel-fired generator (630 hp, runs < 250 hrs/yr) and one emergency diesel-fired fire water pump (280 hp, runs < 850 hrs/yr). In addition, a diesel-fired emergency fire water pump (160 hp) was identified in the application for the Unit 3 project. The initial RICE MACT was published in the Federal Register on June 15, 2004 and the requirements applied to new and existing engines 500 hp or greater located at major sources of HAPs. Under the initial rules, existing emergency engines located at major sources of HAPs were not subject to any requirements (including initial notification) per 63.6590(b)(3) and new emergency engines were only subject to the initial notification requirements per § 63.6590(b)(1)(i). An initial notification was submitted for the new emergency generator on July 23, 2009. Therefore, the new (Unit 3) emergency generator is not subject to any additional RICE MACT requirements.

Note that the source submitted additional information on the emergency generator that is in the insignificant activity list in the current permit. This emergency generator is actually a 530 hp engine, not a 630 hp engine. Nevertheless this emergency generator is not subject to the RICE MACT requirements because it is an existing engine > 500 hp located at a major source for HAPs.

Revisions to the RICE MACT were published in the Federal Register on January 18, 2008 to address new (constructed after June 12, 2006) engines 500 hp or less located at major sources. Under these revisions, existing compression ignition (CI) engines, 2-stroke lean burn (2SLB) and 4-stroke lean burn (4SLB) engines were not subject to any requirements in either Subparts A or ZZZZ (40 CFR Part 63 Subpart ZZZZ § 63.6590(b)(3)). Further revisions to the RICE MACT were published in the Federal Register on May 3, 2010 to address existing (constructed after June 12, 2006) CI engines 500 hp or less located at major sources. It would appear that the new Unit 3

160 hp fire pump engine would be subject to the January 8, 2008 MACT revisions and the existing 280 hp fire pump engine listed in the insignificant activity list in the current permit would be subject to the May 3, 2010 MACT revisions. However, the source submitted additional information indicating that existing 280 hp fire pump was retired and replaced with a new 350 hp fire pump that serves all three units (this engine replaced the proposed 160 hp engine noted in the initial Unit 3 project permit application).

The 350 hp fire water pump engine was manufactured in June 2006 and installed at the site in October 2007. The relevant definition of “construction” in 40 CFR Part 63 Subpart A § 63.2 means “the on-site fabrication, erection, or installation of an affected source.” Since the engine was installed after June 12, 2006, the 350 hp fire pump engine is considered a new engine. As provided for in § 63.6590(c), a “new” emergency engine 500 hp or less located at a major source meets the RICE MACT requirements by meeting the requirements in 40 CFR Part 60 Subpart III.

Industrial, Commercial and Institutional Boilers and Process Heaters MACT (40 CFR Part 63 Subpart DDDDD)

The final rule for industrial, commercial and institutional boilers and process heaters was published in the Federal Register on September 13, 2004. Due to the vacatur, EPA was required to re-promulgate requirements for this source category. Final Boiler MACT requirements were published in the Federal Register on March 21, 2011. Units 1, 2 and 3 are not subject to the Boiler MACT requirements since they are electric utility steam generating units. There are several heaters included in the insignificant activity list in Appendix A of the permit. However, these units do not meet the definition of boiler or process heater specified in the rule (the definition of process heater excludes units used for comfort or space heat). Therefore, the Boiler MACT does not apply to any equipment at this facility.

Gasoline Distribution MACTs

A 300 gallon aboveground gasoline tank is included in the insignificant activity list. There are potential MACT standards that could apply to this operation: Gasoline Distribution (Stage I) – 40 CFR Part 63 Subpart R (final rule published in the Federal Register on December 14, 1994), Gasoline Dispensing Facilities – 40 CFR Part 63 Subpart CCCCCC (final rule published in the Federal Register on January 10, 2008) and Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities – 40 CFR Part 63 Subpart BBBBBB (final rule published in the Federal Register on January 10, 2008). Both of the rules published on January 10, 2008 only apply at area sources. Since this facility is a major source for HAPS, the requirements in those rules do not apply to the gasoline tank at this facility. The Gasoline Distribution (Stage I) MACT applies to bulk gasoline terminals and pipeline break-out stations. The gasoline dispensing equipment at this facility does not meet the definition of a bulk gasoline terminal or a pipeline break-out station. Therefore, none of the MACT requirements associated with gasoline distribution apply to the equipment at this facility.

State Mercury Requirements for Coal-Fired Electric Utility Steam Generating Units

The Colorado Air Quality Control Commission (AQCC) adopted mercury requirements for electric utility steam generating units on October 18, 2007. These requirements are included in Colorado Regulation No. 6, Part B, Section VIII and specify mercury emission limitations for coal-fired electric utility steam generating units. However, since the construction permit for Unit 3 specifies Hg emission limitations and because the December 2004 Settlement Agreement specifies that a plantwide Hg emission limitation be set for all three units, the state-only Hg requirements do not apply at this facility.

Settlement Agreement Plantwide Mercury Limit

Although not specifically noted in the construction permits issued for the Unit 3 project. The Settlement Agreement stipulated that following the startup of Unit 3, PSCo was to test mercury emission control technologies on Units 1 and 2 for a period of one year. Following the year of testing PSCo was required to submit a report to the parties in the Settlement Agreement and no later than two years after startup of Unit 3, PSCo was to comply with a plant wide Hg limit for all three units combined. On May 25, 2011, PSC submitted an application for the plant wide Hg limit. The facility wide limit will take effect on January 1, 2012. More information on the plantwide mercury limit is addressed later in this document.

Regional Haze Requirements

Units 1 and 2 at this facility are subject to the regional haze requirements for best available retrofit technology (BART) and as such a BART analysis was conducted and a construction permit was issued to address the BART requirements. The BART requirements were included in Colorado Construction Permit 07PB0112B (issued September 12, 2008) and the emission limitations were included in Colorado Regulation No. 3, Part F in December 2007. The limitations included in the construction permit (which were also included in Reg 3, Part F) was part of the Division's regional haze state implementation plan (SIP) that was submitted to EPA Region 8 in 2009. EPA indicated that the SIP was not approvable; therefore, the Division addressed the issues raised by EPA and the regional haze requirements for BART units were included in Colorado Regulation No. 3, Part F, which was adopted by the AQCC in January 2011. Since the BART analyses conducted in 2007-2008 were revised and replaced by the January 2011 changes to Regulation No. 3, Part F, PSCo requested that their construction permit be canceled on April 27, 2011. Although the BART construction permit (07PB0112B) was canceled the emission limitations specified in both the BART construction permit and in the January 2011 changes to Regulation No. 3, Part F are the same. The appropriate provisions from Regulation No. 3, Part F for the Comanche units have been included in the draft permit. It should be noted that as specified in Reg 3, Part F, Section VI.A.3, PSCo must comply with the BART limits as expeditiously as practicable, but in no event later than five years after EPA approval of the Regional Haze SIP.

Greenhouse Gases

Greenhouse gas (GHG) emissions from Comanche Station exceed 100,000 tpy CO₂e. Future modifications at this facility will have to be evaluated to determine if GHG emissions are subject to regulation.

III. Discussion of Modifications Made

Source Requested Modifications

April 27, 2006 Renewal Application

In the renewal application, the source did not request any changes to the permit. The renewal application addressed the compliance assurance monitoring (CAM) requirements. In their renewal application, the source determined that only Units 1 and 2 are subject to CAM with respect to the PM emission limitations. Some of the existing equipment was addressed in the Unit 3 project and permitted emissions were revised; therefore, CAM applicability will be discussed, by construction permit, under the September 10, 2010 modification application. The CAM applicability of the equipment that was not addressed in the Unit 3 project is discussed below.

Unit 1 waste ash silo and coal handling system

No physical changes were made to the Unit 1 waste ash silo and the Unit 1 coal handling system (from the pile to the unit) and since this equipment was constructed prior to February 1, 1972, this equipment is still grandfathered from the minor source construction permit requirements. Since the Unit 1 waste ash silo and coal handling system have no emission limitations, they are not subject to CAM.

Units 1 and 2 cooling and service water towers

The cooling and service water towers are equipped with drift eliminators which reduce drift to 0.001%. Without the drift eliminators, uncontrolled PM and PM₁₀ emissions from the cooling and service water towers would exceed the major source level. However, the Division considers that the drift eliminators are not considered a control device. In 40 CFR Part 64, § 64.1, control device means “equipment other than inherent process equipment that is used to destroy or remove pollutants prior to discharge to the atmosphere...For purposes of this part, a control device does not include passive control measures, that act to prevent pollutants from forming, such as the use of seals, lids or roofs to prevent the release of pollutants”. The Division considers that the drift eliminators are considered inherent process equipment and are passive devices and as such are not considered control equipment. Therefore, the Division considers that the CAM requirements do not apply to the Units 1 and 2 cooling and service water towers.

September 7, 2010 Modification Application

The purpose of the September 10, 2010 modification is to roll the Unit 3 project construction permits into the Title V permit. The construction permits were incorporated into Title V permit as follows:

Units 1 (04PB1439) and 2 (11PB859)

Colorado Construction Permit 04PB1439 was issued on July 5, 2005 for Unit 1 and Colorado Construction permit 11PB859 was modified on July 5, 2005 for Unit 2. These construction permits were issued in order to make the SO₂ and NO_x reductions from these units federally enforceable and to include the additional emission limitations and requirements specified in the December 3, 2004 Settlement Agreement between PSCo and the Concerned Environmental Community Parties (CECP). These construction permits include new requirements, as well as requirements that are in the current Title V permit. Those requirements that were included in the Title renewal V permit are as follows:

Unit 1 (04PB1439):

- Conditions 4 through 9 and 16 are already included in the current Title V permit (condition 16 (APEN reporting) is included in the General Conditions).
- Conditions 10, 11 and 12 are new (i.e. not in the current permit) and were included in the renewal permit.

It should be noted that the quarterly emission and fuel use limitations in Conditions 10 and 11 have not been included in the permit, since they only apply for the first year of operation. In addition, the installation and compliance schedule requirements in Condition 12.c have not been included in the permit since they have been completed.

Condition 12 specifies mercury monitoring requirements for this unit. The language in these conditions has been revised to remove the dates from paragraphs d.i and ii since the deadlines have passed.

- The following conditions have been completed and won't be included in the renewal permit: 1 (installation of control equipment, effective date of permit limits), 2 (commence construction), 3 (startup notification – submitted 9/26/08 and 10/16/08), 13 (T5 application – submitted 9/10/10), 14 (operation and maintenance (O & M) plan – submitted 6/1/09) and 15 (self certification – submitted 6/1/09).

Note that although Condition 14 requires the source follow the requirements of the Division-approved O & M plan (the 6/1/09 O & M plan was approved on 12/8/09), in lieu of the O & M plan the Title V permit includes the appropriate

periodic monitoring requirements. Since this permit was issued to make the installation of NO_x and SO₂ controls and the subsequent emission limits federally enforceable and the unit is equipped with NO_x and SO₂ continuous emission monitoring systems (CEMS), monitoring beyond the CEMS is not necessary to monitor compliance with the emission limitations.

Unit 2 (11PB859):

- Conditions 4 through 10 and 17 are already included in the current Title V permit (condition 16 (APEN reporting) is included in the General Conditions).
- Conditions 11, 12 and 13 are new (i.e. not in the current permit) and were included in the renewal permit.

It should be noted that the quarterly emission and fuel use limitations in Conditions 11 and 12 have not been included in the permit, since they only apply for the first year of operation. In addition, the installation and compliance schedule requirements in Condition 13.c have not been included in the permit since they have been completed.

Condition 13 specifies mercury monitoring requirements for this unit. The language in these conditions has been revised to remove the dates from paragraphs d.i and ii since the deadlines have passed.

- The following conditions have been completed and won't be included in the renewal permit: 1 (installation of control equipment, effective date of permit limits), 2 (commence construction), 3 (startup notification – submitted), 13 (T5 application – submitted 9/10/10), 14 (O & M plan – submitted 12/30/08) and 15 (self certification – submitted 12/30/08).

Note that although Condition 14 requires the source follow the requirements of the Division-approved O & M plan (the 12/30/08 O & M plan was approved on 12/8/09), in lieu of the O & M plan the Title V permit includes the appropriate periodic monitoring requirements. Since this permit was issued to make the installation of NO_x and SO₂ controls and the subsequent emission limits federally enforceable and the unit is equipped with NO_x and SO₂ continuous emission monitoring systems (CEMS), monitoring beyond the CEMS is not necessary to monitor compliance with the emission limitations.

Although not specifically identified in Colorado Construction Permits 04PB1439 and 11PB859, both Units 1 and 2 are subject to the following requirements:

- BART emission limitations and monitoring requirements (Colorado Regulation No. 3, Part F, Section IV.A (limits) and VII (monitoring))

Although the BART limits are subject to a future compliance date, the NO_x and SO₂ limitations are numerically the same as those included in the construction

permits, however, the construction permit allows for certain periods to be excluded from the compliance demonstration but the BART limits require that all valid hours be used in the compliance demonstration. Therefore, both emission limitations shall be included in the permit. Note that when the BART limits take effect, the construction permit limits can be streamlined from the permit in favor of the BART limits.

The reporting of excursions (from CAM indicators) that is included in Reg 3, Part F, Section VII.E for BART sources was streamlined from the permit, since reporting of excursions is already required under the CAM requirements.

In addition, the language in Reg 3, Part F, Section VII.E specifying that performance test results for PM testing shall be submitted within 60 days of the tests was streamlined from the permit since the permit currently requires that the results of PM tests be submitted within 45 days of the test.

Settlement Agreement – Plant Wide Mercury Limit

On May 25, 2011, PSCo submitted an application for a plant wide mercury limit. As part of the December 2004 Settlement Agreement for the Unit 3 Project, PSCo committed to establishing and complying with a plant wide mercury limit within two years of startup of Unit 3. PSCo requested a plant wide Hg limit of 0.0130 lb/GWh (13.0×10^{-6} lb/MWh) on an annual average basis. This requested level is less than the case-by-case 112(g) MACT limit of 14.7×10^{-6} lb/MWh (0.0147 lb/GWh) set for Unit 3.

The proposed MACT for EGUs (40 CFR Part 63 Subpart UUUUU), which was published in the Federal Register on May 3, 2011, proposed lower Hg limits for existing units (all three units qualify as existing units) of 0.008 lb/GWh. However, an error was discovered in converting the data and the proposed limit is now 0.013 lb/GWh for existing units. Note that while the MACT was not re-proposed and published in the Federal Register, EPA added a letter from Jeffrey Cole, RTI International to Bill Maxwell, U. S. EPA, OAQPS/SPPD/ESG, dated May 18, 2011, regarding “National Emission Standards for Hazardous Air Pollutants (NESHAP) Maximum Achievable Control Technology (MACT) Floor Analysis for Coal- and Oil-fired Electric Utility Steam Generating Units – REVISED” to the Docket. This letter documents the revised Hg limits of 0.013 lb/GWh. The proposed MACT also allowed for emission averaging for units in the same subcategory located at a single source.

The final MACT for EGUs was signed by the EPA Administrator on December 16, 2011 but has not been published in the Federal Register yet. In the final MACT, the Hg limit remains at 0.013 lb/GWh, on a 30-day rolling average. The final MACT limit also allows for emission averaging for units in the same subcategory located at a single source. However, under the final rule, for the subcategory for “units designed for coal > 8,300 Btu/lb”, sources must demonstrate compliance with a Hg limit of 0.011 lb/GWh, on a 90-day rolling average. Therefore, PSCo’s proposed plant wide Hg limit is numerically consistent with the proposed MACT limit for individual existing EGUs, but lower than the limit established for units that choose to rely on emission averaging. In addition,

PSCo's proposed plant wide Hg limit is based on an annual average, while the MACT specifies a shorter averaging period. All of the units at Comanche Station are considered existing units, which have 3 years from the date the final MACT rule is published in the Federal Register to comply with the MACT requirements. Under the terms of the Settlement Agreement, PSCo must comply with the plant wide Hg limit beginning on January 1, 2012 (because the limit is an annual average, compliance with the limit would be assessed after each unit has completed 365 operating days). Therefore, the Division considers that a slightly lower Hg limit with a longer averaging period is reasonable for the plant wide Settlement Agreement limit.

The Hg testing on Units 1 and 2 was conducted in two phases. The purpose of phase I was to evaluate options for control such as boiler chemical additives (applied to the coal) and several types of Hg sorbents. The phase I testing was conducted on Unit 1 because it has slightly higher baseline (uncontrolled emissions). Following the Phase I test, further testing was done on the most effective option. The phase II testing was conducted on both Units 1 and 2. During the phase II testing, prior to the addition of any sorbent baseline (uncontrolled) operations were monitored to see the normal fluctuations in mercury. Some of the observations during the phase II testing was the high variability of mercury in the coal (it varied by more than a factor of 2), the high variability in the mercury removal rate prior to any sorbent injection (varied between 36% and 78%) and the impact operational factors have on mercury emissions (load and spray dryer operation were noted).

The Settlement Agreement stipulated that the cost of Hg control would be no less than \$2 million per year in the first year's operations and maintenance costs and no more than \$5 million. If PSCo proposed a limit at less than \$5 million per year, PSCo would bear the burden of demonstrating to the Division that a more stringent emission limitation is not cost-effective based on dollar per pound of Hg removed. In the application, PSCo demonstrated that the proposed plant wide Hg limit would cost \$3.6 million in the first year. As required by the Settlement Agreement, since the cost of removal was less than \$5 million, PSCo conducted an analysis of the costs for additional mercury removal. PSCo's analysis was based on the phase I, Unit 1 testing. The analysis evaluated the costs of mercury removal at three sorbent injection rates: 0.27 lb/MMacf (0.016 lb/GWh), 0.55 lb/MMacf (0.012 lb/GWh) and 0.85 lb/MMacf (0.006 lb/GWh). The incremental increase in costs between the 0.27 and 0.55 MMacf sorbent injection rates is \$5,474/lb but increase substantially to \$12,075/lb between the 0.55 and 0.85 MMacf injection rates. Therefore, the Division agrees that a plantwide Hg limit of 0.0130 lb/GWhr is appropriate and meets the requirements of the Settlement Agreement. PSCo's requested plant wide Hg limit has been included in the permit.

CAM Requirements

Units 1 and 2 are subject to SO₂ and NO_x emission limitations under the Acid Rain Program (Section III of the current permit). Pursuant to 40 CFR Part 64 § 64.2(b)(1)(iii), the CAM requirements do not apply to Acid Rain Program emission limitations.

Units 1 and 2 are also subject to various other short-term and long-term SO₂ and NO_x emission limitations (lb/MMBtu limits at 3-hr, 30-day and annual rolling averages and tons/yr limit). In the current Title V permit, Units 1 and 2 are subject to short-term Reg 1 SO₂ limits (3-hr rolling average) and Unit 2 is subject to a short-term NSPS NO_x limit (3-hr rolling average) and the current permit requires that the permittee use their SO₂ and NO_x CEMS to monitor compliance with those limitations. Although the current Title V permit does not include annual mass emissions limits (tons/yr) for SO₂ and NO_x, it does require the source to use their SO₂ and NO_x CEMS to determine annual emissions (tons/yr) for purposes of APEN reporting and fees. The Division considers that CAM does not apply with respect to the new SO₂ and NO_x emission limitation (30-day and annual lb/MMBtu and ton/yr limits) since the current Title V permit requires SO₂ and NO_x CEMS to monitor compliance with the emission limitations and reporting requirements in the current Title V permit in accordance with the provisions in 40 CFR Part 64 § 64.2(b)(1)(iv) (the Title V permit specifies a continuous compliance method).

CAM does apply to the Units 1 and 2 with respect to the PM emission limitations. Note that although these units are subject to opacity limits, they are not emission limitations subject to CAM requirements. The source submitted a CAM plan with their April 27, 2006 renewal application. In their CAM plan, the source proposed visible emissions, pressure differential and preventative maintenance as indicators. For visible emissions, excursions are identified as an opacity value exceeding 15% for one minute or more and any long term increase in opacity of 10% above baseline levels for normal operation. For pressure differential, an excursion is defined as an increase in differential pressure of 3 inches of water column or greater from normal baseline levels accompanied by a sustained increase in opacity over 10%.

In their September 7, 2010 application to modify the Title V permit to incorporate the Unit 3 requirements, a CAM plan was submitted (with respect to PM emission limitations) for all three units. In the September 7, 2010 application, the source proposed visible emissions and preventative maintenance as indicators. For visible emissions, the source proposed an opacity value exceeding 15% for one minute or more and a 24-hour average opacity that exceed the baseline level established by a performance test. For preventative maintenance, the source proposed semi-annual internal baghouse inspections.

The Division's review of the CAM plan submitted with the September 7, 2010 modification application is as follows:

Visible Emissions

The Division accepts the indicator range of 15% opacity for one minute or more and will include this in the permit.

The Division agrees that a sudden spike in opacity is a reasonable indicator that the baghouse operation may have been compromised. The 15% indicator level is below the opacity limitations set for both units. PSCo submitted information on July 14, 2010 indicating that the 15% opacity indicator is based on operating experience. In their

submittal, PSCo indicated that based on their years of operating experience an opacity spike of 15% opacity for 60 seconds or more is generally an indicator that there is a problem with the baghouse and that an opacity spike below that set point would pick up spikes in opacity that are seen with normal operation. Although PSCo has not correlated 15% to a level of PM emissions, this is a short term (one minute or more) indicator of baghouse performance and as specified in 40 CFR Part 64 § 64.4(c)(1), emission testing is not required to be conducted over the indicator range or range of potential emissions. Given that the PM standard is based on the average of three one (1) hour tests and past performance tests indicate that the PM emissions are less than 50% of the standard, the short term 15% opacity indicator serves to provide an indication of proper baghouse operation and as such can be a reasonable indicator that the units are in compliance with the PM limitations.

The Division also accepts the second indicator (24-hour average opacity that exceeds the baseline level established by performance testing). The 24-hour average opacity suggested as a second indicator for visible emissions is similar to the monitoring required for control devices (e.g. baghouses) used to meet the particulate matter standards under NSPS Da. For new (constructed after February 28, 2005) electric utility steam generating units NSPS Subpart Da specifies that a baseline opacity level be established and that any 24-hr average opacity value that exceeds the baseline level shall be cause for investigating the control device.

The 24-hr average opacity indicator range will be set in a manner similar to the methodology specified in 40 CFR Part 60 Subpart Da § 60.48Da(o)(2)(iii), which states that the baseline opacity is established during the performance test by averaging all 6-minute average opacity values from the COMS recorded during each of the test runs and then adding a 2.5% opacity to the calculated average opacity. If the NSPS Da baseline opacity (average during test run plus 2.5%) is less than 5%, then the baseline opacity is set at 5%. Since these units are subject to less stringent particulate matter standards than the NSPS Da standards for new units (0.1 lb/MMBtu vs. 0.015 lb/MMBtu), the Division is allowing an opacity value up to 5% to be added to the calculated opacity average from the performance test. The actual allowable opacity add-on is based on the results of the performance tests. Also, as provided for in NSPS Da, if the baseline opacity (COMS average plus add-on) is less than 5%, then the baseline opacity (i.e., the indicator range) is set at 5%. It should be noted that when the BART PM limits take effect the Division is reducing the allowable opacity add-on to 3.5%, since the PM limit will be 0.03 lb/MMBtu, rather than 0.1 lb/MMBtu. Using a larger opacity add-on is still appropriate since the BART limit is lower than the NSPS Da limit of 0.0150 lb/MMBtu.

Since the 24-hr opacity indicator is very similar to the control device monitoring required for new units under NSPS Da, the Division considers that the 24-hr opacity indicator is acceptable for CAM.

Performance tests were conducted on Units 1 and 2 in February 2011. Based on the results of those tests the 24-hr opacity indicators have been set at 7.7% for Unit 1 and 8.0% for Unit 2.

Preventative Maintenance

The Division accepts PSCo's proposal for semi-annual internal baghouse inspections and will include this in the permit.

In general, the CAM plan has been included in Appendix G of the permit as submitted, except that the corrections indicated above have been made to the plan and some language has been omitted, revised or relocated in order to streamline the plan.

Coal and Oil-Fired Electric Utility Steam Generating Units (40 CFR Part 63 Subpart UUUUU)

The final MACT requirements for electric utility steam generating units were signed on December 16, 2011. Units 1 and 2 qualify as existing units under these requirements and therefore have three years to comply with the MACT requirements. Under the final rule, Units 1 and 2 will be subject to emission limitations for filterable PM (or total non-Hg HAPS or individual non-Hg HAPS), HCl (or SO₂) and Hg and several compliance options are offered for the various pollutants including provisions for low emitting units and emissions averaging for units within the same subcategory, located at a single source. Given the number of compliance options and the fact that existing sources will have three years to comply with the requirements, the permit includes a requirement to submit an application to modify their Title V permit within one year of the compliance date to incorporate the chosen compliance options into the permit.

Unit 3 (04PB1015)

The Unit 3 boiler is an Alstom, Model and Serial No. 63000105-3, tangentially fired dry bottom super critical pulverized coal-fired boiler and is rated at 6,973 MMBtu/hr (maximum continuous rating) and 783 MW (net summer dependable capacity). Natural gas is used for startup, shutdown and flame stabilization.

Applicable Requirements: Colorado Construction Permit 04PB1015 was issued on July 5, 2005 for this unit and was revised on February 22, 2010 to include case-by-case 112(g) MACT requirements. The boiler commenced operation in January 2010 and PSCo submitted a self-certification on July 9, 2010. Therefore, under the provisions of Colorado Regulation No. 3, Part C, Section V.A.3, the Division will not issue a final approval construction permit and is allowing the initial approval construction permit to continue in full force and effect.

The appropriate applicable requirements from the construction permit have been incorporated into the permit in Section II.2 as follows:

- The following conditions have not been included in the permit because they have

been completed: Condition 1 (commence construction), Condition 2 (startup notice), Condition 3 (provide manufacturer information), Condition 22 (Title V application), Condition 23 (O & M plan) and Condition 24 (self certification).

The unit commenced operation in January 2010. A startup notice was submitted on August 5, 2009, with revised notices submitted via e-mail. The source submitted a self-certification on July 9, 2010. The manufacturer and serial number information and an O & M plan were included with the self-certification. The Division approved the O & M plan on December 2, 2010. The Title V permit application was submitted on September 7, 2010.

Note that in lieu of relying on an O & M plan, which is a construction permit requirement, the Title V permit includes the appropriate periodic monitoring necessary to assure compliance with the permit conditions. Given that this emission unit has CEMS for NO_x, SO₂, Hg and CO and is subject to CAM for PM and PM₁₀, additional monitoring methods are not necessary to assure compliance with these emission limitations. Note that this unit is subject to requirements in NSPS Da, which includes a general duty requirement to, at all times, operate and maintain equipment and air pollution control equipment in accordance with good air pollution control practices to minimize emissions.

- Except as provided for below, opacity emissions shall not exceed 20% (condition 5, Reg 1, Section II.A.1)
- Under certain conditions, opacity emissions shall not exceed 30% (condition 6, Reg 1, Section II.A.4)
- BACT requirements (condition 7)

With respect to the PM and PM₁₀ BACT limits, a few changes will be made to the emission limitations and monitoring requirements that are specified in the construction permit.

The construction permit indicates that the Division will consider requiring a PM CEMS upon submittal of the Title V permit application submitted to incorporate Unit 3 into the Title V permit. In their Title V application, PSCo indicated that they considered a PM CEMS to be a viable compliance demonstration methodology and considered that they would be able to utilize a PM CEMS within one year of permit issuance. As such, the Division has included the requirement to operate a PM CEMS within one year of permit issuance. Since a PM CEMS cannot differentiate size, the filterable PM/PM₁₀ limit will be set at 0.0120 lb/MMBtu (the construction permit limits filterable PM to 0.0130 lb/MMBtu and PM₁₀ to 0.0120 lb/MMBtu). In addition, the Division considers that the averaging time for the PM/PM₁₀ filterable limit should be adjusted once compliance is demonstrated via a PM CEMS. Currently compliance with the PM/PM₁₀ limits are based on performance tests and the averaging time for the limits are the average of three test runs (the average of three 2-hour test runs). When PSCo uses the PM

CEMS to monitor compliance with the filterable PM/PM₁₀ emission limitations, the averaging time will be set at a 24-hour rolling average. The 24-hour averaging time is consistent with the short-term PM₁₀ NAAQS (24-hr average) and is similar to the averaging time set for the PM limit in NSPS Da for sources that opt to use a PM CEMS (NSPS Da sets a 24-hr block average for source using a PM CEMS). The change in averaging time from the current permit (average of three test runs) to a 24-hour rolling average with the PM CEMS could be viewed as a relaxation of the BACT limit. However, since the monitoring method in the current permit is intermittent (annual performance tests consisting of three 2-hour test runs) and with the PM CEMS compliance is continuously monitored, the Division does not consider this to be a relaxation of the BACT limit due to the changes in the monitoring method.

The construction permit also indicates that based on the results of the initial performance test for total particulate matter (filterable plus condensable), the Division will consider lowering the limit from 0.020 lb/MMBtu total PM₁₀ to 0.0180 lb/MMBtu total PM₁₀. The results of the performance test conducted in April 2010 indicate that total PM and PM₁₀ is 0.0059 lb/MMBtu, which is well below the current BACT limit of 0.020 lb/MMBtu. However, a second test was conducted in May 2011 and the results of that test indicate total PM and PM₁₀ emissions at 0.0199 lb/MMBtu. Therefore, the total PM/PM₁₀ limit will remain at 0.020 lb/MMBtu. Although the construction permit includes a total PM limit of 0.022 lb/MMBtu and a total PM₁₀ limit of 0.020 lb/MMBtu, since the filterable PM limit was lowered to 0.0120 lb/MMBtu (same as the filterable PM₁₀ limit), the Division considers that the total PM limit should also be the same as the total PM₁₀ limit, since all condensable PM is considered PM₁₀.

The construction permit also indicates that following the initial performance tests conducted to monitor compliance with the H₂SO₄ BACT limit that the Division will consider lowering the limit from 0.0042 lb/MMBtu to no less than 0.0034 lb/MMBtu. The results of the initial performance test conducted in April 2010 indicate emissions of 8.2×10^{-5} lb/MMBtu, which is well below the BACT limit. A second performance test was conducted in May 2011 and the results of that test indicate emissions of 8.55×10^{-5} lb/MMBtu. Therefore, the Division is revising the BACT limit to 0.0034 lb/MMBtu.

- PM emissions shall not exceed 0.1 lb/MMBtu (condition 8, Reg 1, Section III.A.1.c)
- Continuous emission monitoring requirements – SO₂ and opacity (condition 9, Reg 1, Section IV)
- SO₂ emissions shall not exceed 0.4 lb/MMBtu on a 3-hr rolling average (condition 10, Reg 1, Section IV.B.4.a.(iii) and VI.B.2)
- Fuel use limitations (condition 11)

- Annual emission limitations (condition 12)

It should be noted that the quarterly emission and fuel use limitations in Conditions 11 and 12 have not been included in the permit, since they only apply for the first year of operation.

- NSPS Subpart Da requirements (condition 13)

These requirements include PM, NO_x and SO₂ emission limitations and monitoring requirements, as well as the NSPS General Provisions in Subpart A. Note that one time requirements (such as notifications and initial compliance demonstrations) that have been completed will not be included in the draft permit.

- **State-only** New Source Performance Standards (Condition 14, Reg 6, Part B, Section II)

- Settlement Agreement Limitations (condition 15)

Settlement Agreement requirements include SO₂ and NO_x limitations, as well as requirements for Hg, HCl, HF and H₂SO₄. Note that the HF and H₂SO₄ limitations are the same as the BACT limitations. Requirements that have passed (such as compliance dates) will not be included in the draft permit.

Note that the Settlement Agreement included a “good operating practices” requirement in paragraph 8.G. This requirement was included in the construction permits for Units 1 and 2 but not in the construction permit for Unit 3. Since NSPS Da includes a “good operating practices” requirement that is essentially identical to the language in the 8.G of the Settlement Agreement, it is not necessary to include the paragraph 8.G in the permit for Unit 3.

- NO_x emissions shall not exceed 0.07 lb/MMBtu on a 365-day rolling average basis (condition 16)
- A continuous emission monitoring system shall be installed, calibrated, maintained and operated to measure CO emissions (condition 17)
- Performance test requirements for PM, PM₁₀, HCl, HF, H₂SO₄ and VOC (condition 18)

Initial performance tests were conducted on Unit 3 in May 2010. The results of the May 2010 test indicated emissions were below 50% of the standard for total PM and PM₁₀, H₂SO₄, HCl and HF and above 75% of the standard for VOC.

Subsequent performance tests were conducted in May 2011 for PM, PM₁₀, HCl, HF, H₂SO₄ and VOC indicated that emissions were below 50% of the standard for HCl, HF, H₂SO₄ and VOC and above 75% of the standard for total PM and PM₁₀. The test dates and frequency of subsequent testing for total PM and PM₁₀,

HF, H₂SO₄, HCl and VOC has been noted in the permit.

In order to be consistent with the monitoring required by NSPS Da, frequency of performance tests for filterable PM and PM₁₀ has been revised to annual until the PM CEMS is in operation.

- Post-construction monitoring for PM₁₀ and ozone (condition 19)
- **State-only** lead requirements (condition 20, Reg 8, Part C, Section I.B)

Since EPA promulgated a more stringent national ambient air quality standard for lead in 2008, the Division removed the state-only lead requirement from Colorado Regulation No. 8, Part C. Therefore, the requirement will not be included in the draft permit. Note that the lead NAAQS will not be included in the permit as NAAQS are not considered applicable requirements and as such are not included in Title V permits.

- Acid Rain permit application shall be submitted 24 months prior to commencing operation (condition 21)

An acid rain permit application was submitted on November 6, 2006 and an Acid Rain Permit was issued on April 1, 2007. Therefore, this requirement will not be included in the permit. Note that the Acid Rain provisions applicable to this unit will be included in Section III of the permit.

- APEN reporting requirements (condition 25)

The APEN reporting requirements will not be identified in the permit as a specific condition but are included in Section V (General Conditions) of the permit, condition 22.e.

- Case-by-case 112(g) MACT requirements (condition 26)

Note that as previously mentioned, EPA signed final MACT standards for electric utility steam generating units on December 16, 2011. Under the final MACT rule, limitations have not been included for certain pollutants which are addressed in the 112(g) MACT determination for Unit 3 (e.g., the final rule includes an emission limitation for HCl to address acid gases, while the Unit 3 112(g) limitation includes limits for both HCl and HF). Therefore, language will be added to the permit to indicate that if a final MACT rule is published and it doesn't address certain pollutants that are included in the 112(g) MACT determination that those limitations are no longer applicable upon the compliance date for the MACT limitations. This is consistent with the MACT 112(g) requirements which indicate that if a 112(g) determination includes more stringent requirements than an EPA promulgated rule, that it is up to the permitting authority's discretion to require the more stringent case-by-case 112(g) MACT determination.

The permit specifies that compliance with the Hg limit will be based on

performance tests until the Hg CEMS is certified. The EPA Administrator signed off on the final MACT standard for electric utility units on December 16, 2011. The electric utility MACT was published in the Federal Register on February 16, 2012 and the effective date of the requirements was April 16, 2012. The Division certified the Hg CEMS for all units at this facility on April 24, 2012. As a result, the Division removed the language regarding the use of performance testing to monitor compliance with the Unit 3 case-by-case MACT Hg limit. Compliance with the Unit 3 case-by-case MACT Hg limit will be based on the Hg CEMS.

Note that the HG CEMS language was revised to indicate that the CEMS will be operated in accordance with 40 CFR Part 60, Appendix B, Performance Specification 12A and 40 CFR Part 63 Subpart UUUUU since these are the procedures to which the Hg CEMS was certified to. This language was previously based on the Hg CEMS language in Colorado Regulation No. 6, Part B, Section VIII (State Hg Rule), as at the time, there were no other Federal requirements that addressed Hg monitoring for electric utilities.

Settlement Agreement – Plant Wide Mercury Limit

As discussed previously in this document for Units 1 and 2, the Settlement Agreement specified that within 2 years of commencing operation for Unit 3 that PSCo shall comply with a plant wide Hg limit. PSCo submitted an application on May 25, 2011 to incorporate the plant wide Hg limit into the permit. As discussed previously in this document for Units 1 and 2, a plant wide Hg limit of 0.0130 lb/GWh (on a 12-month rolling average) has been included in the permit.

Streamlining of Applicable Requirements

Opacity

Unit 3 is subject to the Reg 1 20% opacity requirement and the Reg 1 30% opacity requirement for certain specific operational activities. The Reg 1 20% opacity requirement applies at all times, except for certain specific operating conditions under which the Reg 1 30% opacity requirement applies. Unit 3 is also subject to the state-only Reg 6, Part B 20% opacity requirement and the NSPS Da opacity requirements (20% / 27%). Finally, Unit 3 is subject to a BACT opacity limit of 10% opacity, except that during startup the BACT limit is 30% (consistent with the Reg 1 30% opacity requirements) and during shutdown the BACT is 20% (consistent with the Reg 1 20% opacity requirement). The NSPS Da opacity requirements are not applicable during periods of startup, shutdown and malfunction in accordance with the requirement in 40 CFR Part 60 Subpart A § 60.11(c). Reg 6, Part B, Section I.A, adopts, by reference, the 40 CFR Part 60 Subpart A general provisions, therefore the Reg 6, Part B 20% opacity requirement does not apply during periods of startup, shutdown and malfunction. As indicated on the opacity grid on page 58, the BACT limits are either more stringent or as stringent as all other opacity requirements at all times. Therefore, all other opacity limits will be streamlined out of the permit in favor of the BACT opacity limit.

SO₂

Unit 3 is subject to SO₂ emission limitations in Reg 1, Reg 6, Part B, NSPS Da, Acid Rain requirements and the construction permit (Settlement Agreement limits in lb/MMBtu and annual mass emission limitations). Only the Reg 1 and Reg 6, Part B limits are in the same units (lb/MMBtu) and have the same averaging period (3-hr rolling).

The Regulation No. 1 and No. 6, Part B SO₂ standards are the same, 0.4 lb/MMBtu. The Regulation No. 6, Part B requirement is a state-only requirement. Reg 6, Part B, Section I.A, adopts, by reference, the 40 CFR Part 60 Subpart A general provisions. Although not specifically stated in the general provisions, the Division has concluded after reviewing EPA determinations that the NSPS standards are not applicable during startup, shutdown and malfunction, although any excess emissions during these periods must be reported in the excess emission reports. Specifically, EPA has indicated (4/18/75, determination control no. A007) that when 40 CFR Part 60 Subpart A § 60.11(d) was developed "...it was recognized that sources which ordinarily comply with the standards may during periods of startup, shutdown and malfunction unavoidably release pollutants in excess of the standards." In addition, EPA has also indicated (5/15/74, determination control number D034) that "[s]ection 60.11(a) makes it clear that the data obtained from these reports are not used in determining violations of the emission standards. Our purpose in requiring the submittal of excess emissions is to determine whether affected facilities are being operated and maintained 'in a manner consistent with good air pollution control practices for minimizing emissions' as required by 60.11(d)." Therefore, the Division considers that the Reg 6, Part B SO₂ requirements do not apply during periods of startup, shutdown and malfunction. Therefore, the Regulation No. 1 SO₂ requirement is more stringent than the Regulation No. 6, Part B requirement and the Regulation No. 6, Part B requirements will be streamlined out of the permit.

The Settlement Agreement limit of 0.10 lb/MMBtu appears to be more stringent than the Reg 1 limit of 0.4 lb/MMBtu. However, the averaging period for the Settlement Agreement limit is a 30-day rolling average and it is likely that the Reg 1 limit could be exceeded without violating the Settlement Agreement limit, therefore, these requirements cannot be compared for stringency so both requirements will be included in the permit.

The NSPS Da limit is in units of lb/MW-hr and as such cannot be compared to either the Settlement Agreement limit or the Reg 1 limit; therefore, the NSPS Da limit will remain in the permit.

Unit 3 is also subject to the Acid Rain SO₂ requirements. Sources subject to Acid Rain must hold adequate SO₂ allowances to cover annual emissions of SO₂ (1 allowance = 1 ton per year of SO₂) for a given unit in a given year. The number of allowances can increase or decrease for a unit depending on allowance availability. Allowances are obtained through EPA, other units operated by the utility or the allowance trading

market and compliance information is submitted (electronically) to EPA. Pursuant to Regulation No. 3, Part C, Section V.C.1.b, if a federal requirement is more stringent than an Acid Rain requirement, both the federal requirement and the Acid Rain requirement shall be incorporated into the permit and shall be federally enforceable. For these reasons, the Acid Rain SO₂ requirements have not been streamlined out of the permit. The source will have to demonstrate compliance with the Acid Rain SO₂ requirements, the construction permit tons/yr limit, the Reg 1 limit, the Settlement Agreement limit and the NSPS Da SO₂ requirements. Note that the Acid Rain SO₂ allowances appear only in Section III (Acid Rain Requirements) of the permit.

PM

Unit 3 is subject to a Reg 1 particulate matter standard, an NSPS Da PM limit and the BACT PM limit. The NSPS Da PM requirement does not apply during periods of startup, shutdown and malfunction, as specifically stated in § 60.48Da(c). The Reg 1 and the BACT particulate matter standards apply at all times. The particulate matter BACT limit is more stringent than both the Reg 1 and NSPS Da limit at all times (see grid on page 59). Currently performance testing is the compliance monitoring method for these PM limits and compliance is based on the average of three test runs. Note that when the source is required to use the PM CEMS, the averaging time for the BACT and NSPS Da limit will be based on a 24-hour rolling average. The Division considers that even with the longer averaging time for the BACT limit (when the PM CEMS is used), it is unlikely that a violation to the Reg 1 limit would not also result in a violation of the BACT limit. Therefore, the Division has streamlined the NSPS Da and the Reg 1 particulate matter limits in favor of the BACT limit.

Hg

Unit 3 is subject to a case-by-case MACT Hg limit and a Hg limit under the Settlement Agreement. Both limits are in lb/MW/hr and are based on 12-month rolling averages. The case-by-case Hg MACT limit is more stringent than the Settlement Agreement Hg limit; therefore, the Division has streamlined the Settlement Agreement limit in favor of the case-by-case MACT limit.

Monitoring

Unit 3 is subject to several types of continuous emission monitoring system (CEMS) requirements. The unit is subject to continuous monitoring requirements in Reg 1 (SO₂ and opacity), NSPS Da (opacity, SO₂ and NO_x - PM CEMS are identified as an option) and Acid Rain (opacity, SO₂ and NO_x). The construction permit did not set out any additional CEMS requirements (except for the CO CEMS which isn't required by either NSPS Da or Acid Rain). The NSPS Da CEMS requirements rely on 40 CFR Part 60, while the Acid Rain CEMS rely on Part 75. Part 75 CEMS requirements are generally considered more stringent and NSPS Da includes provisions for using Part 75 CEMS, since most of the NSPS Da sources are also subject to Acid Rain requirements. Therefore, streamlining of Part 60 and Part 75 CEMS is not necessary. However, the

Division will streamline the Reg 1 continuous monitoring system requirements out of the permit in favor of the Parts 60 and 75 CEMS requirements.

As discussed above, the Division streamlined the NSPS Da PM limit, therefore, the NSPS Da PM monitoring was also streamlined from the permit.

Miscellaneous

Since Unit 3 is subject to federal NSPS requirements (Subparts Da and GG) and state-only NSPS requirements (Reg 6, Part B, Section II), it is subject to the general provisions on a federal and state-only basis. The state-only general provisions will be streamlined in favor of the federal general provisions

CAM Requirements

In their September 7, 2010 application to incorporate the Unit 3 provisions into the Title V permit, the source indicated that CAM applied to Unit 3 with respect to the PM and PM₁₀ emission limitations and proposed as CAM, a short term opacity indicator of 15% (for 60 seconds or more), a 24-hour baseline opacity indicator and semi-annual baghouse inspections. While not specifically mentioned in the CAM plan submitted by PSCo, CAM only applies to the filterable PM and PM₁₀ emission limitations (short-term BACT limitations), which are controlled by the baghouse. Condensable PM and PM₁₀ emissions are considered to be uncontrolled, therefore, CAM does not apply to the total PM and PM₁₀ emission limitations (this includes the short-term BACT limitations and the annual (tons/yr) limitations). In addition, it should be noted that CAM does not apply to the NSPS Da PM limit (this is exempt under 40 CFR Part 64 § 64.2(b)(1)(i)) but does apply to the the Reg 1 PM limit; however, both the NSPS Da and Reg 1 limits have been streamlined in favor of the more stringent filterable PM BACT limit.

Although the Division approved the short term (60 seconds) opacity indicator for Units 1 and 2, this indicator is not appropriate for Unit 3 as the 15% opacity level is higher than the BACT opacity limit of 10% (on a 6-minute average). Therefore, there will be no short-term opacity indicator for Unit 3.

The Division also approves the 24-hour average opacity as an indicator. Unit 3 is a new electric utility unit that is subject to the NSPS Da PM limit, which was streamlined in favor of the filterable PM BACT limit which is more stringent. Although the Division streamlined both the NSPS Da PM limit and the NSPS Da PM monitoring requirements, the 24-hour average opacity indicator will be set in the same manner as specified in NSPS Da § 60.48Da(o)(2)(iii). Since the 24-hr opacity indicator is essentially the same as the monitoring under NSPS Da, the Division considers that 24-hr average opacity indicator is acceptable for CAM.

When PSCo begins using their PM CEMS, the PM CEMS will be used as CAM and excursions shall be defined as any exceedence of the limitations. As specified in 40 CFR Part 64 § 64.3(d)(1), if a CEMS is required, the source shall use such system to

satisfy the CAM requirements. Note that a CAM plan will not be included in the permit for the filterable PM and PM₁₀ limitations, when the PM CEMS is used to satisfy the CAM requirements. Under the CAM requirements CEMS that meet the requirements in 40 CFR Part 60 meet the general design criteria in § 64.3(a) and (b) (see 40 CFR Part 64 § 64.3(d)(2)).

Unit 3 is also subject to emission limitations for SO₂ and NO_x and relies on control devices (lime spray dryer, low NO_x burners with over-fire air and SCR) to meet those limitations. Although low NO_x burners with over-fire air are typically not considered a control device for purposes of CAM (they are considered inherent process equipment), SCR is and as a result Unit 3 is potentially subject to CAM for SO₂ and NO_x.

Unit 3 is subject to SO₂ emission limitations under the Acid Rain Program (Section III of the current permit) and SO₂ and NO_x emission limitations under NSPS Da. As provided for in 40 CFR Part 64 §§ 64.2(b)(1)(i) and (iii), the NSPS Da and Acid Rain limitations are exempt from the CAM requirements. CAM applies to the remaining SO₂ and NO_x limitations (Reg 1 SO₂, Settlement Agreement limits for SO₂ and NO_x and the annual mass (ton/yr) SO₂ and NO_x limitation. The NO_x and SO₂ CEMS will be used to directly monitor compliance with these emission limitations. Note that a CAM plan will not be included in the permit for the NO_x and SO₂ limitations, since compliance will be directly measured by the CEMS. Under the CAM requirements CEMS that meet the requirements in 40 CFR Part 60 or 75 meet the general design criteria in § 64.3(a) and (b) (see 40 CFR Part 64 § 64.3(d)(2)).

The lime spray dryer installed on Unit 3 also reduces acid gas emissions (HCl, HF and H₂SO₄) and Unit 3 is subject to emission limitations for these pollutants. H₂SO₄ is a criteria pollutant and fluorides are also a criteria pollutant. HF and HCl are hazardous air pollutants. Controlled emissions of H₂SO₄, HCl and HF are above the major source level (100 tpy for H₂SO₄ and 10 tpy for HF and HCl), therefore, CAM applies to Unit 3 for H₂SO₄, HF and HCl. As previously indicated, presumptively acceptable CAM includes monitoring for standards that are exempt from CAM pursuant to § 64.2(b)(1)(i) [NSPS or MACT standards proposed after November 15, 1990] or (vi), provided that the monitoring is applicable to the control device (and associated capture system (see § 64.4(b)(4)). Therefore, the Division considers that relying on a monitoring method that is very similar to the monitoring required for an NSPS or MACT standard proposed after November 15, 1990 would be acceptable monitoring for CAM.

The final MACT for coal-fired electric utility steam generating units was signed by the EPA Administrator on December 16, 2011. The final MACT (40 CFR Part 63 Subpart UUUUU) sets standards for acid gases (the limit is set for HCl) and for emission units equipped with a flue gas desulfurization device (FGD), there is an alternate SO₂ limit (SO₂ is the surrogate for acid gases). The final MACT acid gas limit is 0.0020 lb/MMBtu HCl and for units equipped with a FGD and an SO₂ CEMS, the alternate acid gas limit is 0.20 lb/MMBtu SO₂. Sources using the SO₂ limit as an alternate (or surrogate) to the HCl limit must conduct an initial performance test to measure SO₂ (using the SO₂ CEMS and converting hourly emissions to 30-day boiler operating day average in lb/MMBtu)

and thereafter monitor compliance with the SO₂ limit using the SO₂ CEMS (maintaining a 30-boiler operating day rolling average). Sources using the SO₂ alternate must have an FGD and must operate the FGD in accordance with the requirements in 40 CFR Part 63 Subpart UUUUU § 63.10000(b) (operate in a manner consistent with safety and good air pollution control practices for minimizing emissions).

Since Unit 3 is equipped with an SO₂ CEMS and is equipped with a dry FGD, which is operated in a manner consistent with safety and good air pollution control practices for minimizing emissions, the Division considers that monitoring compliance with the SO₂ BACT limit (which is on a 30-day rolling average) is acceptable monitoring for CAM, with respect to the acid gas limits (HCl, HF and H₂SO₄). The results of the performance tests conducted in May 2010 and May 2011 are shown below and indicate that all pollutants are below the allowable limits.

Pollutant/Test Date	Emissions (lb/MMBtu)				
	Run 1	Run 2	Run 3	Average	Limit ¹
HCl and HF/ May 2010	< 6.04 x 10 ⁻⁶ < 2.95 x 10 ⁻⁶	< 5.23 x 10 ⁻⁶ < 2.55 x 10 ⁻⁶	< 5.69 x 10 ⁻⁶ < 2.78 x 10 ⁻⁶	< 5.66 x 10 ⁻⁶ < 2.76 x 10 ⁻⁶	6.2 x 10 ⁻⁴ 4.0 x 10 ⁻⁴
SO ₂ ² / May 2010	0.024	0.021	0.014	0.020	0.10
H ₂ SO ₄ / May 2010	1.71 x 10 ⁻⁴	3.38 x 10 ⁻⁵	4.23 x 10 ⁻⁵	8.23 x 10 ⁻⁵	0.0034
SO ₂ ³ / May 2010	0.0246	0.0246	0.0249	0.0247	0.10
HCl, HF and H ₂ SO ₄ / May 2011	< 1.17 x 10 ⁻⁵ < 1.76 x 10 ⁻⁵ 8.22 x 10 ⁻⁵	< 1.27 x 10 ⁻⁵ < 1.91 x 10 ⁻⁵ 8.98 x 10 ⁻⁵	< 1.39 x 10 ⁻⁵ < 2.10 x 10 ⁻⁵ 8.45 x 10 ⁻⁵	< 1.28 x 10 ⁻⁵ < 1.92 x 10 ⁻⁵ 8.55 x 10 ⁻⁵	6.2 x 10 ⁻⁴ 4.0 x 10 ⁻⁴ 0.0034
SO ₂ / May 2011	0.072	0.072	0.074	0.073	0.10

¹For HCl and HF limits shown are the case-by-case 112(g) MACT limits, which are slightly lower than the HCl Settlement Agreement limit of 6.4 x 10⁻⁴ lb/MMBtu and the HF BACT limit of 4.9 x 10⁻⁴ lb/MMBtu. For SO₂, this is the Settlement Agreement limit.

²SO₂ emissions shown are the results of the SO₂ emissions recorded on the CEMS during the test period. Values shown are average, except for Run 1, which is based on maximum SO₂ emissions rate over the period (note that for Run 1, data from 4:02 through 4:44 is invalid data – due to instrument calibration).

³SO₂ emissions shown are as noted in Table 2-4 of the 2010 Stack Test Report.

Finally, although Unit 3 uses sorbent injection to control Hg emissions and meet the Hg emission limitations in the permit, uncontrolled Hg emissions are well below the major source level. Therefore, CAM does not apply to Unit 3 with respect to Hg emissions.

Coal and Oil-Fired Electric Utility Steam Generating Units (40 CFR Part 63 Subpart UUUUU)

The final MACT requirements for electric utility steam generating units were signed on December 16, 2011. Unit 3 qualifies as an existing unit under these requirements and therefore has three years to comply with the MACT requirements. Under the final rule, Unit 3 will be subject to emission limitations for filterable PM (or total non-Hg HAPS or individual non-Hg HAPS), HCl (or SO₂) and Hg and several compliance options are offered for the various pollutants including provisions for low emitting units and emissions averaging for units within the same subcategory, located at a single source. Given the number of compliance options and the fact that existing sources will have

three years to comply with the requirements, the permit includes a requirement to submit an application to modify their Title V permit within one year of the compliance date to incorporate the chosen compliance options into the permit.

Emission Factors: Annual mass emission limits (tons/yr) for PM, PM₁₀, CO, VOC, HF, and H₂SO₄ are based on the BACT limit, the design heat rate (6,973 MMBtu/hr) and 8760 hrs/yr of operation. Annual mass emission limits for SO₂ and NO_x are based on the Settlement Agreement limit, the design heat rate and 8760 hrs/yr of operation. Unit 3 is equipped with CEMS for SO₂, NO_x and CO; therefore, compliance with the annual mass emission limits for those pollutants will be based on the CEMS. Compliance with the annual mass emission limits for PM, PM₁₀, VOC, HF and H₂SO₄ will be based on the emission factors determined through the performance tests.

Monitoring Plan: Unit 3 is equipped with CEMS for opacity, SO₂, NO_x and CO and will be required to use these CEMS to monitor compliance with the various emission limitations. This unit is also equipped with a Hg CEMS and when the CEMS can be certified the source will be required to use it to monitor compliance with the Hg limitation. Prior to certification of the Hg CEMS, compliance with the Hg limit shall be based on semi-annual stack tests. The permittee will be required to install and operate a PM CEMS within one year of permit issuance. Prior to operation of the PM CEMS, compliance with the filterable PM limitations shall be monitored through annual performance tests and a 24-hour average opacity indicator. Compliance with the VOC, HF, HCl and H₂SO₄ short-term limits are based on performance tests.

Compliance Status: In their Title V permit application, the source noted two past non-compliance issues related to Unit 3. There were two exceedances of the CO BACT limit in July 2010 and the first quarter natural gas throughput limit was exceeded. The non-compliance issues were rectified (operational changes were made to address the CO exceedances and a revised permit was issued to address the exceedance of the natural gas throughput limit) and at the time of application submittal, Unit 3 was in compliance with the applicable requirements in 04PB1015 and so a compliance schedule is not necessary.

Unit 3 Cooling Tower (04PB1016)

The Unit 3 cooling tower is GEA Power Cooling, Model No. 545439-9I-3-FCF, hybrid cooling system consisting of both a wet condenser and cooling tower and dry condenser, with a design water circulation rate of 169,790 gal/min.

Applicable Requirements: The wet condenser and cooling tower are addressed in Colorado Construction Permit 04PB1016, which was first issued on July 5, 2005 and revised on December 8, 2008. The cooling tower commenced operation in January 2010 and PSCo submitted a self-certification on October 19, 2010. Therefore, under the provisions of Colorado Regulation No. 3, Part C, Section V.A.3, the Division will not issue a final approval construction permit and is allowing the initial approval construction permit to continue in full force and effect.

The appropriate applicable requirements from the construction permit have been incorporated into the permit in Section II.5 as follows:

- The following conditions have not been included in the permit because they have been completed: Condition 1 (commence construction), Condition 2 (startup notice), Condition 3 (provide manufacturer information), Condition 10 (O & M plan), Condition 11 (Title V application) and Condition 12 (self certification).

The unit commenced operation in January 2010. A startup notice was submitted on August 5, 2009. The source submitted a self-certification on October 19, 2010. The manufacturer and serial number information and the O & M plan were included with the self-certification. The Division approved the O & M plan on December 2, 2010. The Title V permit application was submitted on September 7, 2010.

Note that in lieu of relying on an O & M plan, which is a construction permit requirement, the Title V permit includes the appropriate periodic monitoring necessary to assure compliance with the permit conditions. The appropriate operating and maintenance requirements will be included in the permit.

- opacity emissions shall not exceed 20% (condition 5, Reg 1, Section II.A.1)

Although there is a Reg 1 opacity limit of 30% (Reg 1, Section II.A.4) that applies to emission units under certain operating conditions, in processing the initial construction permits the Division considered that the specific operating conditions did not apply to the cooling tower and as such the 30% opacity standard did not apply.

- BACT requirements (condition 6)
- Throughput limits (condition 7)
- Annual emission limitations (condition 8)

It should be noted that the quarterly emissions and throughput limits in Conditions 7 and 8 have not been included since they only apply during the first year of operation.

- Sample Circulating Water quarterly (condition 9)
- APEN reporting requirements (condition 13)

The APEN reporting requirements will not be identified in the permit as a specific condition but are included in Section V (General Conditions) of the permit, condition 22.e.

CAM Requirements

The cooling water tower is equipped with drift eliminators which reduce drift to 0.0005% or less. Without the drift eliminators, uncontrolled PM and PM₁₀ emissions from the cooling and service water towers would exceed the major source level. However, as discussed previously for the Units 1 and 2 cooling and service water towers, the Division considers that the drift eliminators are not considered a control device and as a result, CAM does not apply.

Emission Factors: Compliance with the PM, PM₁₀ and chloroform emissions from the Unit 3 cooling water shall be monitored using the following equations:

$$PM = \frac{\text{water flow, gal/min} \times 60 \text{ min/hr} \times 8,760 \text{ hr/yr} \times \text{water density, lb/gal} \times (\% \text{ drift}/100) \times (\text{total solids, lb PM}/10^6)}{2000 \text{ lb/ton}}$$

Where: % drift = 0.0005%
Total solids = based on quarterly sampling (lb PM/10⁶ lb water)
Density of water = 8.34 lb/gallon

$$PM_{10} = 0.24 \times PM$$

Where: 0.24 = weight fraction of PM₁₀ to PM, per "Calculating Realistic PM₁₀ Emissions from Cooling towers", J. Reisman, G. Frisbie, Presented at 2001 AWMA Annual Meeting

$$VOC = CHCl_3 = \frac{\text{water flow, gal/minute} \times 60 \text{ min/hr} \times 8,760 \text{ hrs/yr} \times (0.0527 \text{ lb } CHCl_3/10^6 \text{ gal})}{2000 \text{ lb/ton}}$$

Where: 0.0527 lb/MMgal emission factor - from letter from Wayne C. Micheletti to Ed Lasnic dated November 11, 1992

Note that the calculation method for the Unit 3 cooling water tower is different from the methods used to estimate emissions from the Units 1 and 2 cooling and service water towers. The methods used to estimate emissions from the Units 1 and 2 towers, are based on the assumption that only 31.3 % of the drift is dispersed (per EPA-600/7-79-251a, November 1979, "Effects of Pathogenic and Toxic Materials Transported Via Cooling Device Drift - Volume 1, Technical Report", page 63) and that all PM = PM₁₀. The Division considers that the method used to calculate PM and PM₁₀ emissions from the Unit 3 cooling tower is reasonable.

Monitoring Plan: Compliance with the annual emission and throughput limitations shall be monitored by recording water circulated and calculating emissions monthly. Quarterly samples of the circulating water shall be taken to determine the total solids concentration for use in the emission calculations. Although this tower is subject to the 20% opacity requirements, the Division considers that opacity emissions from the cooling tower are unlikely to exceed 20%. Therefore, in the absence of credible evidence to the contrary, compliance with the opacity standard is presumed, provided the cooling tower and associated drift eliminators are operated and maintained in accordance with manufacturer's recommendations and good engineering practices

Compliance Status: In the Title V permit application, the source indicated that the Unit 3 cooling tower was in compliance with all applicable requirements.

Coal Handling (04PB1017)

Emissions from coal handling and storage consist of both fugitive and non-fugitive sources. Fugitive sources include rail car unloading and the storage pile, while non-fugitive sources include the conveyors and crushers. As part of the Unit 3 project, a new rail car unloader was built, as well as a lowering well (used to off-load coal to the storage pile) for the Unit 3 storage pile. While the Units 1 and 2 lowering well and pile were essentially unchanged, new conveyors were built to bring the coal from the new unloader to the Units 1 and 2 lowering well, hence the lowering well and pile were considered modified and addressed as part of the Unit 3 project. The Units 1 and 2 reclaim conveying system (transfer of coal from the storage pile to the units) and crushers were not modified as part of the Unit 3 Project. Although there were no changes to the Unit 2 reclaim conveying system and crusher, the emission limits were revised as part of the Unit 3 project because a new calculation method was used. Construction commenced on the Unit 1 reclaim conveying system and crusher prior to February 1, 1972 and the system was not modified as part of the Unit 3 project; therefore, the system is grandfathered from construction permit requirements.

Applicable Requirements: Colorado Construction Permit 04PB1017 was issued for the Units 2 and 3 coal handling systems, the rail car unloader, conveyors from unloader to pile and the storage piles on July 5, 2005 and modified on September 12, 2007. PSCo self-certified compliance with the conditions in Colorado Construction Permit 04PB1017 on July 9, 2010. Therefore, under the provisions of Colorado Regulation No. 3, Part C, Section V.A.3, the Division will not issue a final approval construction permit and is allowing the initial approval construction permit to continue in full force and effect.

The appropriate applicable requirements from the construction permit has been incorporated into the permit in Section II.3 as follows:

- The following conditions have not been included in the permit because they have been completed: Condition 2 (commence construction), Condition 3 (startup notice), Condition 4 (provide manufacturer information), Condition 12 (Title V application), Condition 13 (O & M plan) and Condition 14 (self certification).

Limited operation of the rail car unloader occurred in August 2009 and full operation of the entire Unit 3 coal handling system occurred in January 2010. A startup notice was initially submitted on September 9, 2008 with additional notifications submitted later to address delays. The source submitted a self-certification on July 9, 2010. The manufacturer and serial number information for the baghouse and the O & M plan were included with the self-certification. The Division approved the O & M plan on February 7, 2011. The Title V permit application was submitted on September 7, 2010.

Note that in lieu of relying on an O & M plan, which is a construction permit requirement, the Title V permit includes the appropriate periodic monitoring necessary to assure compliance with the permit conditions. The appropriate operating and maintenance requirements will be included in the permit.

- opacity emissions shall not exceed 20% (condition 6, Reg 1, Section II.A.1)

Although there is a Reg 1 opacity limit of 30% (Reg 1, Section II.A.4) that applies to emission units under certain operating conditions, in processing the initial construction permits the Division considered that the specific operating conditions did not apply to the coal handling equipment.

- BACT requirements (condition 7)
- Throughput limits (condition 8)
- Annual emission limitations (condition 9)

It should be noted that the monthly emissions and throughput limits in Conditions 8 and 10 have not been included since they only apply during the first year of operation.

- NSPS Subpart Y requirements (condition 10)

These requirements include opacity limitations, as well as the NSPS General Provisions in Subpart A. Note that one time requirements (such as notifications and initial compliance demonstrations) that have been completed will not be included in the draft permit.

Final revisions to NSPS Subpart Y were published in the Federal Register on October 8, 2009 as part of a periodic review and update by EPA. Since the new rail car unloader and associated conveyors and the Unit 3 coal handling system commenced construction prior to April 28, 2008, the October 8, 2009 revisions do not apply.

- Performance test requirement for Unit 3 transfer tower baghouse (condition 11)

A performance test was conducted on the transfer tower baghouse on May 7, 2010. The results of the performance test indicated emissions of 0.006 gr/dscf, which is less than the BACT limit of 0.01 gr/dscf. Since the results of the performance test were well below the BACT limit further performance testing of the baghouse will not be required.

- APEN reporting requirements (condition 15)

The APEN reporting requirements will not be identified in the permit as a specific condition but are included in Section V (General Conditions) of the permit, condition 22.e.

- Fugitive particulate matter control requirements for coal handling and storage (condition 16)

In a letter dated December 15, 2010, the Division indicated that due to complaints and an opacity reading that exceeded 20%, a revised fugitive dust control plan was to be submitted as required under Reg 1, Section III.D.1.c. PSCo submitted a revised fugitive dust control plan dated February 8, 2011. In a letter dated March 14, 2011, the Division notified PSCo of another documented instance of off-property transport of fugitive dust and requested an update to the proposed fugitive dust control measures by the end of April 2011. PSCo submitted a revised fugitive dust control plan on August 9, 2011 and the Division approved it on August 31, 2011. The revised fugitive dust control measures were included in the permit.

- Provisions for the operation of the rotary rail car unloader (condition 17)

CAM Requirements

As previously indicated, since the Unit 1 coal handling system does not have emission limitations, the unit is not subject to CAM.

The Units 2 and 3 coaling handling system (conveyors and crushers) and the fugitive coal handling sources (storage piles and rail car unloader) are subject to emission limitations. Many of the conveyor transfer points and the crushers are enclosed to reduce emissions. The definition of control device in 40 CFR Part 64 § 64.1 states the following: “[f]or purpose of this part, a control device does not include passive control measures that act to prevent pollutants from forming, such as seals, lids, or roofs to prevent the release of pollutants”, therefore the Division considers that enclosures are not control devices under CAM and those emission sources utilizing enclosures to reduce emissions are not subject to CAM.

Water sprays are used as control measure at the rail car unloader and at the storage piles. The use of water to reduce fugitive or visible emissions can certainly be considered a control measure used to reduce emissions and meet emission limitations. However, the Division does not consider that water sprays meet the definition of a control device for purposes of CAM. The preamble to the CAM rule provides more insight into the control device definition and provides the following (from October 22, 1997 Federal Register, page 54912, 3rd column, under *control devices criterion*)

The final rule provides a definition of “control device” that reflects the focus of Part 64 on those types of control devices that are usually considered as “add-on” controls.” This definition does not encompass all conceivable control approaches but rather those types of control devices that may be prone to upset and malfunction, and that are most likely to benefit from monitoring of critical parameters to assure that they continue to function properly. In addition, a regulatory obligation to monitor control devices is appropriate because these devices

generally are not a part of the source's process and may not be watched as closely as devices that have a direct bearing on the efficiency or productivity of the source.

The Division considers that the use of water sprays to reduce fugitive and/or visible emissions is not an add-on control device and is not the type of device that would benefit from monitoring critical parameters. Therefore, the Division considers that water sprays do not meet the definition of a control device under CAM and those emission sources using water sprays to reduce emissions are not subject to CAM.

Some of the transfer points within the Units 2 and 3 coaling handling system are routed to baghouses, which are considered control devices. Using the uncontrolled emission factors and the permitted coal throughput limits, uncontrolled emissions from these transfer points are below the major source level. Permitted emissions from the two Unit 3 transfer points that are controlled by a baghouse were set based on the BACT limit (the baghouse grain-loading guarantee of 0.01 gr/dscf). Based on these permitted emission levels, uncontrolled emissions would be above the major source level assuming a control efficiency of less than 90% for the baghouse. However, the Division considers that it is more appropriate to determine uncontrolled emissions based on the throughput limit and an uncontrolled emission factor. Therefore, CAM does not apply to any of the transfer points controlled by a baghouse.

Emission Factors: For purposes of monitoring compliance with the emission limitations, the following emission factors shall be used:

Transfer Points

Emissions for all transfers of coal from rail car to hoppers, conveyor to conveyor, or from lowering well to pile were estimated using the following equation.

$$E = \frac{k \times 0.0032 \times (U/5)^{1.3} \times D \times \text{tons of coal}}{(M/2)^{1.4}}$$

Where: E = particulate emissions, lb/yr
k = particle size multiplier, dimensionless
k = 0.74 for PM (< 30 µm)
k = 0.35 for PM₁₀
U = mean wind speed, mph
D = number of drop or transfer points, dimensionless
M = moisture content, %

Emission factors are from AP-42, Section 13.2.4 (dated 11/06), Aggregate Handling and Storage Piles, Equation 1 for drop or transfer points.

Permitted emissions were estimated based on the following information: A coal moisture content of 20% was used. For enclosed transfers a wind speed of 1 mph was used to simulate the cover. For unenclosed transfers a wind speed of 8.2 mph was used and the appropriate control efficiency was used (i.e. 70% control for water sprays and enclosure for unloading from rail car to hopper and 50% control for the dust suppressant applied for transfer from lowering wells to pile).

For both the Units 1 and 2 coal handling system two transfers are controlled by dust collectors. For these transfers emissions were estimated using a wind speed of 8.2 mph to represent uncontrolled emissions and an assumed dust collector control efficiency of 99.9%.

Unit 3 Transfers Controlled by Baghouse

$$\text{Emissions (PM and PM}_{10}\text{)} = \frac{0.01 \text{ gr/dscf} \times 36,400 \text{ scfm} \times 60 \text{ min/hr}}{7,000 \text{ gr/lb}} = 3.12 \text{ lbs/hr}$$

Note that while the above method for the Unit 3 baghouse vent is different from the calculation methods used for the existing coal handling transfers equipped with baghouses, it is consistent with the emission calculations performed for the other sources subject to a BACT grain-loading limit. In addition, emissions calculated using the grain-loading limit are most likely very conservative.

Coal Crushers

<u>Pollutant</u>	<u>Emission Factor</u>
PM	0.02 lb/ton coal
PM ₁₀	0.006 lb/ton coal

Emission factors are from EPA's WebFIRE, SCC 3-05-010-10.

A control efficiency of 99% was used with the Unit 3 crusher, which is enclosed and equipped with a water spray system. A control efficiency of 90% was used for the Units 1 and 2 crushers because they are enclosed.

Unit 3 coal handling (conveying and crushing) permit limits are based on the crusher, 2 enclosed transfer points and 2 transfers controlled by a baghouse.

Unit 2 coal handling (conveying and crushing) permit limits are based on the crusher, 3 enclosed transfer points (one is from the dumper to the Units 1 and 2 lowering well) and 2 transfers controlled by a dust collector.

Unit 1 coal handling (crushing and conveying) emissions are estimated based on the crusher, 1 enclosed transfer and 2 transfers controlled by a dust collector.

Coal Pile Wind Erosion (fugitive emissions)

$$E = 1.7 \times (s/1.5) \times [(365-p)/235] \times (f/15)$$

Where: E = emissions, in lb/day/acre
s = silt content of aggregate, percentage [PSCo used 2.2%, per AP-42 (dated 1/95), Table 13.2.4-1 (coal as received from coal-fired power plant)]
p = number of days with > 0.01 inches of precipitation per year [PSCo used 80, per AP-42 (dated 1/95), Figure 13.2.2-1]
f = percentage of time that wind speed exceeds 5.4 m/s at mean pile height [PSCo used 22.2 % from Pueblo Airport 10 meter – 1985 - 1986]

Emission factors are from "Control of Open Fugitive Dust Sources", EPA-450/3-98-008, dated September 1998, Section 4.1.3.

Permitted emissions are based on inactive pile sizes of 2 acres and active pile sizes of 6 acres. A 50% control efficiency was used for water sprays used to control emissions at the pile.

Coal Pile Maintenance (fugitive emissions)

$$E, \text{ PM} = \frac{78.4 \times s^{1.2}}{M^{1.3}}$$

$$E, \text{ PM}_{10} = 0.75 \times \frac{(18.6 \times s^{1.5})}{M^{1.4}}$$

Where: E = emissions, in lb/hr
s = silt content, in percent [PSCo used 2.2% per AP-42 (dated 1/95), Table 13.2.4-1 (coal as received from coal-fired power plant)]
M = moisture content, % [PSCo used 20 % which represents the mean for "as received coal" according to Comanche coal data)]

Emission factors are from AP-42 (dated July 1998), Section 11.9 (Western Surface Coal Mining), Table 11.9-1 to estimate emissions from coal dozing.

Emissions were estimated based on bulldozing occurring 8,760 hrs/yr. In addition, a control efficiency of 50 % was used for water sprays.

Permitted fugitive emissions are based on the following: wind erosion from the Units 1 and 2 and Unit 3 active and inactive storage piles; bulldozing at the Units 1 and 2 and Unit 3 active storage piles; emissions from the rail car dumper and emissions from off-loading coal from the Units 1 and 2 and Unit 3 lowering wells to the storage piles.

Monitoring Plan: The source will be required to record the quantity of coal processed and calculate emissions monthly in order to monitor compliance with the annual limitations. In addition, annual method 9 observations will be required on the baghouse and dust collectors to monitor compliance with the opacity limitations. The source will be required to conduct weekly inspection of the fugitive activities associated with the coal handling system to ensure the emission control elements are in place and effective. Records of the weekly inspections shall be maintained.

Compliance Status: In the Title V permit application, the source indicated these sources were in compliance with all applicable requirements. However, in letters dated December 15, 2010 and March 14, 2011, the Division noted that the guidelines (20% opacity, off-property transport of visible emissions) for submission of a revised fugitive dust control have been triggered and requested that a revised fugitive dust control plan be submitted. The Division's review of the guideline triggering events indicated that the required fugitive particulate matter control measures specified in the permit were being implemented during those times. As previously stated, the revised fugitive dust control plan was submitted on August 9, 2011, approved by the Division on August 31, 2011 and the requirements of that plan have been included in the permit.

Control Device Support Equipment: Recycle Ash Handling (04PB1018), Lime Handling (04PB1019) and Sorbent Handling (04PB1020)

Applicable Requirements: A number of new emission units were permitted as part of the Unit 3 project to support the emission control technologies that would be installed on all three units. Colorado Construction Permit 04PB1018 (first issued on July 5, 2005 and modified on November 7, 2008) addresses recycle ash handling (6 recycle ash silos and 6 recycle ash mixers – 2 for each unit). Colorado Construction Permit 04PB1019 (first issued July 5, 2005 and modified on September 12, 2007) addresses lime handling equipment (2 lime storage silos and 3 ball mill slakers). Colorado Construction Permit 04PB1020 (issued on July 5, 2005) addresses sorbent handling equipment (2 silos for Units 1 and 2 and 2 silos for Unit 3).

The equipment addressed in these permits have commenced operation and PSCo submitted self-certifications for the permits as follows:

04PB1018: Self-certifications were submitted on December 30, 2008 (Unit 2), May 19, 2009 (Unit 1) and August 11, 2010 (Unit 3). 04PB1019: Self-certification was submitted

on December 30, 2008 (lime silos and slakers serve all three units). 04PB1020: Self-certification was submitted on July 9, 2010 and August 11, 2009 (Unit 3)

Therefore, under the provisions of Colorado Regulation No. 3, Part C, Section V.A.3, the Division will not issue final approval construction permits and is allowing the initial approval construction permits to continue in full force and effect.

The appropriate applicable requirements from the construction permits have been incorporated into the permit in “new” Section II.14 as follows:

- The following conditions have not been included in the permit because they have been completed: Condition 1 (commence construction), Condition 2 (startup notice), Condition 3 (provide manufacturer information), Conditions 9 & 10 (O & M plan) Conditions 10 & 11 (Title V application), and Conditions 11 & 12 (self certification).

The self-certifications were submitted as indicated above. Manufacturer’s information and the O & M plan were submitted with the self-certifications. The O & M plans were approved on February 18, 2009 (04PB1018 and 04PB1019) and January 19, 2010 (04PB1020). Startup notices were submitted as follows: 04PB1018: October 16, 2008 (Unit 1) and August 5, 2009 (Unit 3), 04PB1019: March 7, 2008 and 04PB1020: December 30, 2008 (Units 1 and 2) and October 30, 2009 (Unit 3).

Note that in lieu of relying on an O & M plan, which is a construction permit requirement, the Title V permit includes the appropriate periodic monitoring necessary to assure compliance with the permit conditions. The appropriate operating and maintenance requirements will be included in the permit.

- opacity emissions shall not exceed 20% (condition 5 – all permits, Reg 1, Section II.A.1)

Although there is a Reg 1 opacity limit of 30% (Reg 1, Section II.A.4) that applies to emission units under certain operating conditions, in processing the initial construction permits the Division considered that the specific operating conditions did not apply to these silos, mixers and slakers and as such the 30% opacity standard does not apply.

- BACT requirements (condition 6 – all permits)
- Throughput limits (condition 7 – all permits)
- Annual emission limitations (condition 8 – all permits)

It should be noted that the monthly emissions and throughput limits in Conditions 7 and 8 have not been included since they only apply during the first year of operation.

In addition, in a March 11, 2011 e-mail, the source requested that the permitted emission limits for the recycle ash equipment be revised and submitted an APEN on April 29, 2011 for this purpose. The new requested limits are set for each unit, rather than per silo or mixer (note that there are 2 silos and 2 mixers for each unit). The recycle ash emission limits have been revised to the following: Units 1 and 2 silos: PM and PM₁₀ - 2.06 tons/yr, Units 1 and 2 mixers: PM and PM₁₀ - 0.86 tons/yr, Unit 3 silos: PM and PM₁₀ - 2.91 tons/yr and Unit 3 mixers: PM and PM₁₀ - 0.86 tons/yr

- Performance test requirements (04PB1019, condition 9)

The permit specified that one silo and one slaker were to be tested to monitor compliance with the PM and PM₁₀ emission limitations. In lieu of testing a lime silo and lime slaker, the permittee could test any silo or mixer/slaker addressed in permits 04PB1018 and 04PB1020 in order to meet the performance test requirements. Performance tests were conducted on August 27 and 28, 2008 on the Unit 2 "B" ash silo and the Unit 2 "A" ball mill slaker. The results of the testing indicated grain loading levels of 0.001 gr/dscf which is well below the BACT limits of 0.01 gr/dscf and 0.015 gr/dscf for the silo and slaker, respectively. Therefore, this requirement will not be included in the permit. In addition, given that the performance testing indicated emission levels well below the standard, the Division considers that further testing on these units is not warranted.

- APEN reporting requirements (04PB1018 & 04PB1020 - condition 12 and 04PB1019 - condition 13)

The APEN reporting requirements will not be identified in the permit as a specific condition but are included in Section V (General Conditions) of the permit, condition 22.e.

CAM requirements

All of the silos are equipped with baghouses and the ball mill slakers and recycle ash mixers are equipped with scrubbers. Permitted emissions for these emission units were based on the manufacturer's grain loading guarantee's, the blower's design rate (scfm) and 8760 hrs/year of operation. The BACT limits for the silos were included in units of gr/dscf, since information in EPA's RACT/BACT/LAER Clearinghouse (RBLC) indicates that BACT limits for silos are typically set in those units. Therefore, the annual tons/yr limits were set based on the grain loading specifications. However, using this basis to set the annual emission limitations makes estimating uncontrolled emissions difficult.

Based on the permitted emission limitations for the mixers and slakers, the scrubber control efficiency would have to be 99.6% or greater for uncontrolled emissions to exceed the major source level (100 tons/yr). The Division does not consider that the scrubbers achieve that level of control; therefore, the Division considers that the slakers and mixers are not subject to CAM.

For the silos, using the same method to determine uncontrolled emissions (backing out uncontrolled emissions based on permitted emissions and the control device efficiency) indicates that uncontrolled emissions would be above the major source level at less than 90% control efficiency for the recycle ash silos and at 99.8% control efficiency for the sorbent silos. Uncontrolled emissions would be below the major source level at a control efficiency of 99.9% for the lime silos. Based on this evaluation, the recycle ash silos would be subject to CAM and the other silos would not. Performance tests have indicated emissions from the silos are well below the grain loading limit (0.001 gr/dscf per August 27, 2008 test). The emission limits have been set based on the grain loading limit, not based on throughput. The Division generally considers that emissions are related to throughput levels; therefore, CAM applicability was assessed based on the throughput limits. For emission factors, the Division used an uncontrolled emission factor of 0.61 lb/ton (from AP-42 (dated 2/98) Section 11.17, Table 11.17-4, product loading, enclosed truck), which has been used to estimate emissions from recycle ash and lime silos for other PSCo facilities. Based on this method, uncontrolled emissions from the lime and sorbent silos are below the major source level but emissions from the recycle ash silos are above the major source level and subject to CAM. Note that these calculations are based on the assumption that the permitted throughput can be handled through one silos.

A CAM plan was not submitted for the recycle ash silos with the September 7, 2010 application to incorporate these units into the Title V permit. However, the Division considers that daily visible emission observations are an appropriate parameter to monitor for these baghouses as CAM and has included daily visible emission observations into the permit as CAM.

Emission Factors: For purposes of monitoring compliance with the annual emission limitations, emissions shall be calculated using the emission factors, in lb/hr, shown in the table below. The lb/hr emission factors were calculated using the following equation:

$$\text{PM and PM}_{10} \text{ (lb/hr)} = \frac{\text{BACT limit (gr/dscf)} \times \text{maximum air flow (scfm)} \times 60 \text{ min/hr}}{7,000 \text{ gr/lb}}$$

Emission Unit	BACT Limit (gr/dscf)	Maximum Air Flow (scfm)	PM and PM ₁₀ Emission Factor (lb/hr)
Units 1 & 2 Recycle Ash Silos ¹	0.01	5476	0.47
Unit 3 Recycle Ash Silo ¹	0.01	7760	0.67
Recycle Ash Mixers	0.015	763	0.10
Lime Silos	0.01	200	0.017
Lime Slakers	0.015	710	0.091
Sorbent Silos	0.01	500	0.043

¹emission factors are per unit (2 silos per unit)

Note that performance testing conducted on a representative silo and slaker indicated emissions were well below these levels.

Monitoring Plan: Compliance with the annual emission and throughput limitations shall be monitored by recording throughput and hours of operation monthly and calculating emissions. The method 9 opacity observations conducted for the silos, mixers and slakers all indicated no visible emissions and the performance tests conducted on the silo and slaker indicated PM emissions well below the limitations. Since the Division considers that it is unlikely that opacity limits will be exceeded for any of these emissions units, no further opacity monitoring will be required. In the absence of credible evidence to the contrary, compliance with the opacity standard is presumed, provided the silos, slakers and mixers and their associated baghouses and scrubbers are operated and maintained in accordance with manufacturer's recommendations and good engineering practices.

Compliance Status: In the Title V permit application, the source indicated that these emission units are in compliance with all applicable requirements.

Fly Ash, Flue Gas Desulfurization (FGD) Waste and Spent Sorbent Handling (04PB1021)

Emissions from the waste ash silos are generated during silo loading and unloading and these emissions are considered point source emissions. Emissions from the ash/FGD waste/spent sorbent landfill are generated during haul truck unloading and landfill maintenance and are considered fugitive emissions. A new waste ash silo was installed for Unit 3 as part of the Unit 3 project. Although there were no physical changes to the Unit 2 waste ash silo and to the landfill, due to the increased throughput that would occur, a permit modification was necessary. Note that the Unit 1 waste ash silo commenced construction prior to 1972 and as such was not subject to permitting requirements. Although an increase in throughput through the Unit 1 ash silo is expected due to the Unit 3 project (increased throughput due to FGD waste and spent sorbent), the throughput increase does not trigger permitting requirements for this emission unit.

Applicable Requirements: Colorado Construction Permit 04PB1021 was issued for the Units 2 and 3 waste ash silos and the ash landfill on July 5, 2005. PSCo self-certified compliance with the conditions in Colorado Construction Permit 04PB1021 on December 30, 2008 (Unit 2 silo) and September 10, 2010 (Unit 3 silo). Therefore, under the provisions of Colorado Regulation No. 3, Part C, Section V.A.3, the Division will not issue a final approval construction permit and is allowing the initial approval construction permit to continue in full force and effect.

The appropriate applicable requirements from the construction permit has been incorporated into the permit in Section II.4 as follows:

- The following conditions have not been included in the permit because they have been completed: Condition 2 (commence construction), Condition 3 (startup notice), Condition 4 (provide manufacturer information), Condition 11 (Title V application), Condition 12 (O & M plan), and Condition 13 (self certification).

The Unit 3 waste ash silo commenced operation in January 2010. A startup notice was submitted on August 5, 2009. The source submitted self-certifications on December 30, 2008 (Unit 2) and September 10, 2010 (Unit 3). The O & M plan was included with the self-certification. Note that the self certifications indicated that manufacturer's information and serial numbers were not available (no control device unique to the silos). The Division approved the O & M plan on December 18, 2009. The Title V permit application was submitted on September 7, 2010.

Note that in lieu of relying on an O & M plan, which is a construction permit requirement, the Title V permit includes the appropriate periodic monitoring necessary to assure compliance with the permit conditions. The appropriate operating and maintenance requirements will be included in the permit.

- opacity emissions shall not exceed 20% (condition 6, Reg 1, Section II.A.1)

Although there is a Reg 1 opacity limit of 30% (Reg 1, Section II.A.4) that applies to emission units under certain operating conditions, in processing the initial construction permits the Division considered that the specific operating conditions did not apply to these silos.

- BACT requirements (condition 7)

BACT for silo unloading from both Units 2 and 3 was determined to be unloading through enclosed screw conveyors, to an enclosed pug mill where the material shall be mixed with water prior to loading in trucks. Prior to the Unit 3 project ash was unloaded from the Unit 2 silo dry, into enclosed trucks. In their January 13, 2012 comments on the draft permit, PSCo requested that they be able to unload ash from the Unit 2 silo during those periods when the pug mill is not operational. During those periods, the ash would be unloaded dry, into enclosed trucks via a hose attachment. This alternate option has been included in the draft permit.

Regarding their request to unload the Unit 2 silo dry, during periods of pug mill inoperability, PSCo indicated that they would wet the dry fly ash/FGD waste/spent sorbent as the truck is unloaded at the landfill. Therefore the fugitive particulate control measures at the landfill have been revised to address this possible situation.

- Throughput limits (condition 8)
- Unloading of the silos and operations at the landfill shall occur between the periods of 6 am and 6 pm (condition 9)
- Annual emission limitations (condition 10)

It should be noted that the monthly emissions and throughput limits in Conditions 8 and 10 have not been included since they only apply during the first year of operation.

- APEN reporting requirements (condition 14)

The APEN reporting requirements will not be identified in the permit as a specific condition but are included in Section V (General Conditions) of the permit, condition 22.e.

- Fugitive particulate matter control requirements for the landfill (condition 16)

CAM Requirements

As previously indicated, since the Unit 1 ash silo does not have emission limitations, the unit is not subject to CAM.

Both the Units 2 and Unit 3 silos are subject to emission limitations for PM and PM₁₀ and there are essentially two operations associated with the silo: loading and unloading. Loading ash into the silos from the boiler baghouses is performed by a blower system that pneumatically conveys the ash from the baghouse hoppers to the top of the ash silo. At this point, ash falls into the silo while the conveying air is drawn out of the silo by a vent fan which keeps the silo under constant negative pressure of –1 to –3 inches of water. The exhaust from the silo vent fan is connected to the boiler baghouse inlet duct. Therefore, air from the ash silo ultimately vents through the boiler baghouse for particulate control and out the boiler stack. Therefore, in the silo loading situation, emissions are controlled by the boiler baghouse. Uncontrolled emissions from loading of both the Unit 2 and Unit 3 silo are below the major source level, therefore, CAM does not apply to silo loading. When the silo is unloaded (the second operation), the ash is blended with water in a pug mill and then the wetted ash is unloaded into an open truck. When the ash is wetted, it “sets-up” like cement and has a rock or aggregate like consistence, which reduces PM and PM₁₀ emissions. The Division does not consider that the pug mill meets the definition of a control device under CAM. Therefore, since no control device is used when the silos are unloaded, CAM does not apply to silo unloading.

Although the ash landfill is subject to PM and PM₁₀ emission limitations and uses water sprays as a control measure, the Division does not consider that water sprays are control devices as defined under CAM.

Emission Factors: For purposes of monitoring compliance with the emission limitations, the following emission factors shall be used:

Silos (non-fugitive)

Silo Loading:

PM: 0.61 lb/ton

PM₁₀: 0.61 lb/ton

Emission Factors are AP-42 (dated 2/98), Section 11.17, Table 11.17-4, Product Unloading - Enclosed Truck.

A control efficiency of 99.9% can be applied provided the boiler baghouses are operated and maintain in accordance with manufacturer's recommendations and good engineering practices.

Silo Unloading:

$$E = k \times 0.0032 \times (U/5)^{1.3} \times \text{tons of ash unloaded} \\ (M/2)^{1.4}$$

Where: E = particulate emissions, lb/yr
k = particle size multiplier, dimensionless
k = 0.74 for PM (< 30 µm)
k = 0.35 for PM₁₀
U = mean wind speed, mph. 8.2 mph shall be used in calculations
M = moisture content, %. Based on pug mill operation, 20% is used

Emission factors are from AP-42, Section 13.2.4 (dated 11/06), Aggregate Handling and Storage Piles, Equation 1 for drop or transfer points. Note that the above equation is based on one drop (pug mill to truck).

In their January 13, 2012 comments on the draft permit and technical review document, PSCo requested that they be allowed to unload ash from the Units 1 and 2 ash silos dry, during those times when the pug mill is not operational. In instances when dry loading occurs, emissions shall be emissions using the following emission factor: PM = PM₁₀ = 0.61 lb/ton (from AP-42 Section 11-17 (dated 2/98), Table 11.7-4, "product loading enclosed truck"). A control efficiency of 95% can be applied provided the hose is attached, operated and maintained in accordance with good engineering practices.

Landfill (fugitive):

Truck Unloading:

The same emission factors and assumptions used for silo unloading were used to estimate emissions from unloading trucks at the landfill. Again, emissions are based on one drop (truck to landfill)

Landfill Maintenance:

$$\text{PM (lb/hr)} = \frac{5.7 \times s^{1.2}}{M^{1.3}}$$

$$\text{PM}_{10} \text{ (lb/hr)} = \frac{1.0 \times s^{1.5} \times 0.75}{M^{1.4}}$$

Where: M = material moisture content - 20% used based on pug mill operation
S = material silt content (%) - 62.1 % was used based on PSCo estimate (weighted average of fly ash silt content (80% per AP-42, Table 13.2.4-1 (dated 11/06) and 1% for scrubber sludge.

Emission factors are from AP-42, Section 11.9 (dated 7/98), Western Surface Coal Mining, Table 11.9-1 - bulldozing overburden

An 80% control efficiency may be used provided additional watering, if necessary, is done at the landfill to reduce fugitive particulate matter emissions.

Monitoring Plan: In order to monitor compliance with the emission and throughput limitations, the permittee will be required to record the material processed monthly and calculate emissions. During silo loading, emissions vent through the boiler baghouse; therefore, further opacity monitoring will not be required. The source will certify semi-annually that the fugitive particulate matter control measures have been utilized. This is not a separate semi-annual certification but the certification submitted with the semi-annual monitoring and permit deviation report.

Compliance Status: In the Title V permit application, the source indicated that these emission units are in compliance with all applicable requirements.

Haul Roads (04PB1022)

Waste fly ash, FGD waste and spent sorbent is hauled from the waste ash silos from all three units to the ash/FGD landfill. Bottom ash from Unit 3 is hauled from the bottom ash storage area and hauled to the ash/FGD landfill. Bottom ash from Unit 1 and 2 are periodically removed from the holding ponds and hauled to the ash/FGD landfill. In general, the haul roads are not new (the Unit 3 only segments are), with the Unit 3 project the haul roads will see more traffic, hence higher emissions. Therefore a construction permit was issued with the Unit 3 project permits to address the haul roads.

Applicable Requirements: Colorado Construction Permit 04PB1022 was first issued on July 5, 2005 and modified on May 15, 2009. The provisions in this permit took effect upon startup of Unit 3 (January 2010). PSCo self-certified compliance with the conditions in Colorado Construction Permit 04PB1022 on October 19, 2010. Therefore, under the provisions of Colorado Regulation No. 3, Part C, Section V.A.3, the Division will not issue a final approval construction permit and is allowing the initial approval construction permit to continue in full force and effect.

The appropriate applicable requirements from the construction permit has been incorporated into the permit in “new” Section II.15 as follows:

- The following conditions have not been included in the permit because they have been completed: Condition 10 (Title V application), Condition 11 (recordkeeping plan), and Condition 12 (self certification).

The source submitted a self-certification on July 9, 2010. The recordkeeping plan was included with the self-certification. Note that the appropriate recordkeeping requirements are included in the permit. The Title V permit application was submitted on September 7, 2010.

- BACT requirements (condition 2)
- Traffic on haul trucks on the haul roads shall occur between the periods of 6 am and 6 pm only (condition 3)
- Haul truck capacity (condition 4)

- Haul truck trips – daily limit (condition 5)
- Limits on materials hauled (condition 6)
- Emission limitations (condition 7)

It should be noted that the monthly emissions and material limits in Conditions 6 and 7 have not been included since they only apply during the first year of operation.

- Fugitive particulate matter control plan requirements (condition 8)
- Modified fugitive particulate matter control plan is required under certain conditions (condition 9)
- APEN reporting requirements (condition 13)

The APEN reporting requirements will not be identified in the permit as a specific condition but are included in Section V (General Conditions) of the permit, condition 22.e.

CAM Requirements

The haul roads are subject to PM emission limitations and utilize control measures, such as the addition of water sprays and chemical stabilizers to reduce PM emissions but the Division considers that these control measures are not control devices as defined under CAM. Therefore, CAM does not apply to the haul roads.

Emission Factors: For purposes of monitoring compliance with the annual emission limitations, emissions shall be calculated using the following equation (from AP-42, Section 13.2.2 (dated 11/06), equations 1a and 2) :

$$E = k \times (s/12)^a \times (W/3)^b \times ((365-p)/365)$$

where: E = particulate emissions, in lb/VMT
 VMT = vehicle miles traveled per year
 k = constant, dimensionless, see table below
 a = constant, dimensionless, see table below
 b = constant, dimensionless, see table below
 s = silt content of road surface material, in % (PSCo used 5.1%, per AP-42, Table 13.2.2-1, for coal mine plant road)
 p = number of days with > 0.01 inches of precip. (PSCo – used 80 from AP-42, figure 13.2.2-1)
 W = mean weight of vehicle, in tons (per PSCo 56.75, the average of empty 39.25 and full 74.25 weights)

Constant	PM ₁₀	PM
K	1.5	4.9
a	0.9	0.7
b	0.45	0.45

A control efficiency of 90% can be applied to the above equation to simulate the paved roads. In addition a control efficiency of 80% was applied to the above equation for daily watering/chemical stabilization on the unpaved roads.

Monitoring Plan: The source will be required to monitor the quantity of material hauled and calculate emissions monthly in order to monitor compliance with the annual limits for emissions and material hauled. The source will also be required to record the quantity of vehicle miles traveled monthly to be used in the monthly emission calculations. In addition, the number of daily haul truck trips shall be recorded and used to monitor compliance with the daily haul truck trip limit. The source will certify semi-annually that the fugitive particulate matter control measures have been utilized. This is not a separate semi-annual certification but the certification submitted with the semi-annual monitoring and permit deviation report.

Compliance Status: In the Title V permit application, the source indicated that haul roads are in compliance with all applicable requirements.

Emergency Generator (08PB1178)

The Unit 3 emergency generator is a Caterpillar, Model No. 3516DITA, serial No. SBJ00412, diesel fuel-fired unit, rated at 2,937 hp (2,000 kW) and 18.8 /hr (139 gal.hr).

The Unit 3 emergency generator is used to safely shutdown Unit 3 in the event of a total power failure at the facility. Electrical output from this unit would be used to run critical cooling pumps and motors and to insure that no damage is done to the turbine generator system during a shutdown without power to the plant.

Applicable Requirements: The emergency generator is addressed in Colorado Construction Permit 08PB1178, which was issued on December 8, 2008. The emergency generator commenced operation in July 2009 and PSCo submitted a self-certification on January 6, 2010. Therefore, under the provisions of Colorado Regulation No. 3, Part C, Section V.A.3, the Division will not issue a final approval construction permit and is allowing the initial approval construction permit to continue in full force and effect.

The appropriate applicable requirements from the construction permit have been incorporated into the permit in "new" Section II.16 as follows:

- The following conditions have not been included in the permit because they have been completed: Condition 1 (commence construction), Condition 2 (startup notice), Condition 3 (provide manufacturer information), Condition 13 (O & M

plan), Condition 14 (self certification) and Condition 15 (Title V application).

The emergency generator commenced operation in July 2009. A startup notice was submitted on July 15, 2009. The source submitted the self-certification on January 6, 2010. The O & M plan and manufacturer's information was included with the self-certification. The Division approved the O & M plan on April 20, 2011. The Title V permit application was submitted on September 7, 2010.

Note that in lieu of relying on an O & M plan, which is a construction permit requirement, the Title V permit includes the appropriate periodic monitoring necessary to assure compliance with the permit conditions. The appropriate operating and maintenance requirements will be included in the permit.

- Except as provided for below, opacity emissions shall not exceed 20% (condition 4, Reg 1, Section II.A.1)
- Under certain conditions, opacity emissions shall not exceed 30% (condition 5, Reg 1, Section II.A.4)
- BACT requirements (condition 7)
- Throughput limits (condition 8)
- Emission limitations (condition 9)
- SO₂ emission shall not exceed 0.8 lb/MMBtu (condition 10, Reg 1, Section IV.B.4.b.(i))
- NSPS Subpart IIII requirements (condition 11)

Note that only the current fuel specification requirements will be included in the permit (the 15 ppm requirement took effect on October 1, 2010 and the 500 ppm requirement no longer applies).

- MACT Subpart ZZZZ requirements (condition 12)

This engine was only subject to the initial notification requirements. The initial notification was submitted on July 23, 2009. Note that a second initial notification was submitted for this engine on August 19, 2010 for this unit. It appears that the August 19, 2010 initial notification was intended to address the March 3, 2010 revisions to NSPS ZZZZ. The emergency generator was addressed in the initial MACT ZZZZ requirements (final rule published June 15, 2004), not the March 3, 2010 revisions therefore, it was not necessary to address this emergency generator in the August 19, 2010 notification.

- APEN reporting requirements (condition 16)

The APEN reporting requirements will not be identified in the permit as a specific

condition but are included in Section V (General Conditions) of the permit, condition 22.e.

CAM Requirements

This engine is not equipped with a control device, therefore, this engine is not subject to CAM.

Streamlining of Applicable Requirements

The engine is subject to NSPS Subpart IIII requirements, which includes a limitation on the sulfur in the diesel fuel (sulfur content not to exceed 15 ppm). The engine is also subject to a Reg 1 SO₂ emission limitation of 0.8 lb/MMBtu. Assuming a diesel fuel density of 7.05 lb/gal and a heat content of 137,000 Btu/gal (per AP-42, Appendix A (dated 9/85, reformatted 1/95), the NSPS fuel sulfur limit is equivalent to 1.54×10^{-3} lb/MMBtu. Therefore, the Reg 1 SO₂ limit will be streamlined out of the permit in favor of the NSPS fuel sulfur limit.

Emission Factors: The emission factors used to estimate emissions for this unit are shown in the table below:

Pollutant	Division's Emission Factors	
	Factor	Source ¹
PM	0.15 g/hp-hr	NSPS Limit
PM ₁₀	0.15 g/hp-hr	NSPS Limit Assuming all PM = PM ₁₀
SO ₂	0.97 lb/hr	Calculated using a fuel sulfur content of 0.05 weight percent
NO _x ²	41.87 lb/hr	Manufacturer's data sheet, "Not to exceed data" at 100% load
VOC ³	1.13 lb/hr	Manufacturer's data sheet, "Not to exceed data" at 50% load
CO	2.61 g/hp-hr	NSPS limit

¹Note that the NSPS limits are in g/kw-hr, they were converted to g/hp-hr (1 kw-hr = 1.341 hp-hr).

²Note that the NO_x emission estimates from the manufacturer exceed the NSPS limits; however, the NSPS emission limits are calculated from a percent of the emissions at various loads and then totaled. Although this engine has been certified to meet the NSPS emission limits, annual emissions are based on the NO_x emission rate at 100% load.

³VOC emissions are based on manufacturer's data, rather than the NSPS limit, since the NSPS limit is for NO_x-HC.

Note that since PM, PM₁₀, SO₂, CO and VOC emissions are below the APEN de minimis levels at the requested fuel consumption rate, emission limits for these pollutants were not included in the construction permit and will not be included in the Title V permit.

The NO_x emission factor in the above table was converted to lb/gal by dividing the lb/hr emission factor by the maximum hourly fuel consumption rate (139 gal/hr) and the lb/gal emission factor of 0.3 lb/gal is included in the permit.

Monitoring Plan: Compliance with the annual NO_x emission limitation shall be monitored by recording fuel consumption and calculating emissions monthly. Compliance with the NSPS limitations is presumed since the engine is certified by the manufacturer. The NSPS does not specify how the permittee is required to monitor compliance with the fuel limitations; therefore, the permit will require that the source initially sample the tank (if the tank is full prior to permit issuance) and to sample each shipment of diesel fuel. In lieu of sampling, the permittee may use vendor data to demonstrate compliance with the fuel limitation. Compliance with the opacity limitations shall be monitored by conducting a Method 9 observation annually.

Compliance Status: In the Title V permit application, the source indicated that emergency generator is in compliance with all applicable requirements.

Emergency Fire Pump Engine

An emergency fire pump engine was identified in the Unit 3 construction permit application submitted on August 6, 2004 and at that time the fire pump engine was considered exempt from the APEN reporting and construction permit requirements. Construction permits were issued for the Unit 3 project on July 5, 2005. On July 11, 2006, EPA published in the Federal Register final NSPS requirements for compression ignition engines (the requirements are codified in 40 CFR Part 60 Subpart IIII). The AQCC later adopted these revisions into Colorado Regulation No. 6, Part A. As a result if the engine is subject to the requirements in 40 CFR Part 60 Subpart IIII, then under the "catch-all" language in Colorado Regulation No. 3, Part A, Section II.D.1, Part B, Section II.D and Part C, Section II.E, the engine is not exempt from APEN reporting requirements, construction permit requirements and cannot be considered an insignificant activity.

At the request of the Division, the source submitted additional information on the emergency fire pump engine, indicating that the engine was manufactured in June 2006 and installed on site in October 2007. NSPS Subpart IIII applies to owners/operators of engines that commenced construction after July 11, 2005 and were manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 11, 2006. Under NSPS IIII, the definition of commence construction is the date the engine was ordered. The source was unable to provide the date the engine was ordered but because the engine was originally planned to serve Unit 3 only and the construction permits were issued for Unit 3 on July 5, 2005, the Division considers that construction commenced on the engine after July 11, 2005. However, because the engine was manufactured prior to July 1, 2006, the engine is not subject to any requirements under NSPS Subpart IIII. Therefore, the engine is still exempt from the APEN reporting and construction permit requirements.

As previously stated, the engine is considered a “new” emergency engine and is subject to the RICE MACT requirements. Compliance with the RICE MACT is met by complying with the requirements in NSPS IIII. Although the engine is not subject to the requirements in NSPS Subpart IIII, no further RICE MACT requirements apply to this engine. Under the “catch-all” provisions in Reg 3, Part C, Section II.E, an emission unit that is subject to MACT requirements cannot be considered an insignificant activity. While the engine is subject to the RICE MACT, it is not subject to any requirements under the MACT. Therefore, the Division considers that this engine is an insignificant activity and it has been included in the insignificant activity list in Appendix A of the permit.

January 13, 2012 Comments on the Draft Permit and Technical Review Document

The following changes were made in response to the comments submitted on January 10, 2012 on the draft permit and technical review document:

Section I, Condition 4

- PSCo indicated that chlorine is no longer used at the plant and as a result the facility is no longer subject to the Accidental Release Prevention Program.

Appendix A – Insignificant Activity List

- The listing for “sulfuric acid tank – 15,000 gal above ground” was revised to add 5,000 and 4,500 gallon tanks.
- The listing for “liquid alum tank – 12,500 gal above ground” was revised to list tank sizes of 8,000 and 2,500 gallons. There is no 12,500 gallon tank.
- The listing for the “1,034 gal diesel tank for refueling heavy coal handling equipment” was revised to list the tank size as 2,000 gallons.
- The listing for the “1,000 gallon diesel fuel tank for emergency generator” was revised to indicate the tank is actually a 1,030 gallon tank that is used for the Units 1 and 2 emergency generator.
- A 2,600 gal diesel fuel tank supplying the Unit 3 emergency generator was added under the category “storage tanks with annual throughput less than 400,000 gas/yr”.
- The listings for “north fuel oil tank, 325,000 gal” and “south fuel oil tank, 325,000 gal” were removed since the tanks no longer exist.
- The listing for the “15,000 gallon caustic tank” and related insignificant category were removed.

- Listings for “two carbon dioxide tanks (12,000 lbs and 15,000 lbs)”, “three 10% sodium hypochlorite tanks (6,000, 4,500 and 8,000 gallons), and “Depositrol P 5200 tank (1,000 gallon)” were added under the category “emissions of pollutants which are not criteria or non-criteria reportable pollutants”
- A listing for a “30,000 gallon aqueous ammonia tank” was added under a new category for “units with emissions less than APEN de minimis – non-criteria pollutants”.

Other Modifications

In addition to the modifications requested by the source, the Division has included changes to make the permit more consistent with recently issued permits, include comments made by EPA on other Operating Permits, as well as correct errors or omissions identified during inspections and/or discrepancies identified during review of this renewal.

The Division has made the following revisions, based on recent internal permit processing decisions and EPA comments, to the Comanche Station Operating Permit with the source’s requested modifications. These changes are as follows:

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- Monitoring and compliance periods and report and certification due dates are shown as examples. The appropriate monitoring and compliance periods and report and certification due dates will be filled in after permit issuance and will be based on permit issuance date. Note that the source may request to keep the same monitoring and compliance periods and report and certification due dates as were provided in the original permit. However, it should be noted that with this option, depending on the permit issuance date, the first monitoring period and compliance period may be short (i.e. less than 6 months and less than 1 year).
- Changed the responsible official and permit contact.
- Revised to indicate that the permit is issued to “Public Service Company of Colorado”. This change is also reflected in the headers and footers.

Section I - General Activities and Summary

- Revised the description in Condition 1.1 to address changes to the facility.
- Revised the list on construction permits in Condition 1.3 to reflect new and remove canceled permits.
- Section V, Conditions 3.d and 3.g (last paragraph) were added as state-only requirements in Condition 1.4. Note that Section V, Condition 3.d (affirmative defense provisions for excess emissions during malfunctions) is state-only until

approved by EPA in the SIP. In addition, Section II, Condition 1.10 was removed from the list of state-only conditions.

- Condition 3 (PSD) was revised as follows:
 - Condition 3.1 was revised to correct some Reg 3 citations.
 - Condition 3.2 was revised to indicate that there are no other Operating Permits associated with this facility (BMTI requested that their Title V permit be cancelled on April 4, 2012).
- Revised Condition 5.1 to reflect CAM (the current condition indicates that CAM does not apply until renewal).
- The following changes were made to the table in Condition 6.1:
 - Added a column for the startup date of the equipment.
 - Removed the third column labeled “facility id”, as these numbers are the same as the emission unit numbers. The first column was relabeled “emission unit number/facility identifier”.
 - The new equipment associated with the Comanche 3 project was added to table.

Section II.1 – Boilers, Coal-Fired

The following changes were made in addition to incorporating the requirements from the construction permits that were issued as part of the Unit 3 project.

- Revised the language in Condition 1.1.2 (PM performance test requirements) to specify that the performance tests shall be used to set the baseline opacity for the CAM plan and specify how the baseline opacity shall be determined.
- Revised Condition 1.7 (fuel sampling) to remove lead.
- Condition 1.10 was revised to remove the state-only lead standard of $1.5 \mu\text{g}/\text{m}^3$. Since EPA promulgated a more stringent national ambient air quality standard for lead in 2008, the Division removed the state-only lead requirement from Colorado Regulation No. 8, Part C. Therefore, the requirement is being removed from the permit. Note that the lead NAAQS will not be included in the permit as NAAQS are not considered applicable requirements and as such are not included in Title V permits.
- Removed the requirement in Condition 1.14 to submit a copy of the Acid Rain annual compliance certification to the Division. The Acid Rain rules were revised and no longer require that annual certifications be submitted.
- Added the CAM language as “new” Condition 1.20.

Section II.2 – Boilers 1 and 2 – Natural Gas for Startup and Flame Stabilization

- This section was removed. The construction permits issued for Units 1 and 2 as part of the Unit 3 project, limit natural gas use for each unit to 5% of the total heat content of the unit. As a result this section is no longer necessary. Note that requirements for Unit 3 have been included in this section.

Section II.3 – Particulate Matter Emissions – Fugitive Sources

- This section has been revised to address coal handling and storage operations (both point and fugitive emission sources).

Section II.4 – Particulate Matter Emissions – Ash and Coal Handling

- This section has been revised to include both ash handling and storage operations (both point and fugitive emission sources).

Section II.6 – NSPS General Provisions

- Removed the reference to Colorado Regulation No. 1, Section VI.B.4.a.(iv) in the citation for Condition 6.1. The good practices language in Colorado Regulation No. 1 has been removed.

Section II.7 – Particulate Matter Emission Periodic Monitoring Requirements

- Removed the language in Condition 7.1 regarding the COMS and opacity spikes. The Division considers that with the CAM plan requirements this language is no longer necessary.
- Condition 7.1 was separated into two conditions, one related to baghouse operation and maintenance for the boilers and the other for operation and maintenance of the baghouses and dust collectors used in the coal handling system.
- Revised the stack testing language in Condition 7.2 to clarify the frequency of testing. The language in the permit addresses testing within the expected five-year permit term. The permit terms may be extended, provided a timely and complete renewal application has been submitted. For the most part, complete and timely renewal applications have been submitted and the term of the permits have been extended beyond the originally anticipated five-year permit term. Therefore, the language has been revised to set specific deadlines for testing, which more appropriately reflects the Division's intent to require testing for particulate matter at a minimum of every five years. To that end, the language regarding waiving testing within the last two years of the permit term, in the event that annual testing was triggered, has been removed. In general, the results of the initial tests have not been above 75% of the standard and annual testing has

not been triggered. Therefore, the Division considers that the language is not necessary.

Section II.8 – Continuous Emission Monitoring System Requirements

- The formatting and numbering within this condition has changed in order to include provisions for the Unit 3 CO CEMS and the additional NSPs Da requirements for the SO₂ and NO_x CEMS for Unit 3.
- Removed the phrase “and the traceability protocols of Appendix H” from Condition 8.3.2, since Appendix H of the current version of 40 CFR Part 75 is “reserved”. Note that Condition 8.3.1 specifies that the continuous emission monitoring systems are subject to the requirements of 40 CFR Part 75 and that would include any applicable appendices, regardless of whether or not they are specifically called out in this condition.
- Removed the language in Condition 8.3.2 related to monitoring compliance with the SO₂ limitations in Condition 1.3.
- Replaced the phrase “concerning upset conditions and breakdowns” with “concerning affirmative defense provisions for excess emissions during malfunctions” in Condition 8.5.5 to reflect revisions made to the Division’s Common Provisions Regulation.
- Added language to clarify that the data acquisition and handling system (DAHS) shall be able to manipulate data in the units of all emission limitations and to require that relative accuracy test audits (RATAs) be conducted in units of all emission limitations.
- Data replacement requirements were added. SO₂, NO_x and CO (Unit 3 only) are subject to data replacement requirements in 40 CFR Part 75 and the replaced data shall be used to monitor compliance with the annual (tons/yr limitations).
- The phrase “may elect to” in the first paragraph of Condition 8.4.4 (monitoring requirements when the COMS is down) was replaced with “shall”.

Section II.9 – Opacity Requirements and Periodic Monitoring Requirements

- The monitoring language in Conditions 9.1 and 9.2 require the installation of COMS; however, the requirement to install COMS is addressed in the permit conditions for the respective emissions units. Therefore the requirement to install COMS was removed and the permit specifies that the COMS be used to monitor compliance with the emission limitations. A reference to the specific permit condition requiring the COMS has been included.

Section II.10 – Lead Periodic Monitoring

- Removed Condition 10.1 (Reg 8 lead standard).

Section III – Acid Rain Requirements

- Revised the Designated Representative and Alternate Designated Representative.
- Revised the table in Section 2 to include calendar years corresponding to the relevant permit term for the renewal.
- Revised the NO_x limit in the table in Section 2. The source had elected to comply with the Phase I NO_x requirements in 1997. Beginning in January, the source was subject to the Phase II NO_x requirements. Therefore, those limits have been included in the permit.
- Removed Section 3, since the NO_x early election expired beginning in January 2008.
- Minor changes were made to the standard requirements (Section 4), based on changes made to 40 CFR Part 72 § 72.9.
- Removed the requirement in Section 5 (Reporting Requirements) to submit a copy of any revised certificate of representation to the Division. Submitting a copy of the certificate of representation to the permitting authority is not required under the regulations.
- Removed the requirement to submit the annual reports and compliance certifications in Section 5. As a result of revisions to the Acid Rain Program made with the Clean Air Interstate Rule (final published in the Federal Register on May 12, 2005), annual compliance certifications are no longer required, beginning in 2006. Note that although the CAIR rule was vacated (July 2008), this revision was unrelated to the CAIR rule and it is expected that these changes will not be affected by the CAIR vacatur. Note that in December 2008, the vacatur of the CAIR rule was over-turned.
- Added a new “Section 5” for “comments, notes and justification” to explain why Unit 3 has no NO_x limits under the Acid Rain Program.

Section IV – Permit Shield

- The citation for the permit shield has been revised to remove Reg 3, Part C, Section V.C.1.b and C.R.S. § 25-7-111(2)(l) since they don’t address the permit shield.
- Revised the permit shield for the provisions in NSPS Subpart Y in the table in Section IV.3 (permit shield for non-applicable requirements) to specifically

identify those portions that are not subject to NSPS Subpart Y. Note that with the Unit 3 project some coal handling equipment is subject to NSPS Subpart Y.

Section V - General Conditions

- Added a version date to the General Conditions.
- Revisions were made to the Common Provisions Regulation (general condition 3), on July 18, 2002 (effective September 30, 2002) and December 15, 2006 (effective March 4, 2007). The appropriate revisions were made to the language in the permit. The July 18, 2002 revisions were minor in nature. The December 15, 2006 revisions replaced the upset provisions with the affirmative defense provisions for excess emissions during malfunctions. Note that these provisions for malfunctions are state-only enforceable until approved by EPA into Colorado's state implementation plan (SIP). In addition, removed the statement in 3.g (affirmative defense for excess emissions during startups and shutdowns) indicating that they are state-only, as Section I, Condition 1.4 identifies those portions of 3.g that are state-only enforceable.
- Replaced the reference to "upset" in Condition 5 (emergency provisions) and 21 (prompt deviation reporting) with "malfunction".
- The title for Condition 6 was changed from "Emission Standards for Asbestos" to "Emission Controls for Asbestos" and in the text the phrase "emission standards for asbestos" was changed to "asbestos control".
- The citation in General Condition 17 (open burning) was revised. The open burning requirements are no longer in Reg 1 but are in new Reg 9. In addition, changed the reference in the text from "Reg 1" to "Reg 9".
- General Condition No. 21 (prompt deviation reporting) was revised to include the definition of prompt in 40 CFR Part 71.
- Replaced the phrase "enhanced monitoring" with "compliance assurance monitoring" in General Condition No. 22.d.
- General Condition 29 was revised by reformatting and adding the provisions in Reg 7, Section III.C as paragraph e.

Appendices

- The following changes were made to the insignificant activity list in Appendix A:
 - The 280 hp emergency fire pump engine was removed.
 - The category for the emergency generator and fire pump engines were revised.
- The following changes were made to Appendices B and C:

- Replaced with the latest versions.
- Included the new equipment from the Unit 3 project in the tables.
- The following changes were made to Appendix D:
 - Changed the mailing address for EPA.
 - Removed the Acid Rain addresses in Appendix D, since annual certification is no longer required and submittal of quarterly reports/certifications is done electronically.
 - Changed the name of the Division contact for reports.
- Cleared the modification information from the table in Appendix F (this table starts anew with the renewal).

PSCo – Comanche Total HAP Emissions

Emission Unit	Emissions (tons/yr)						Total
	HCl	HF	Non-Hg Metals	Hg	organic HAPs	chloroform	
Unit 1	2.42	4.59	12.65	3.91E-02	2.27		22.20
Unit 2	4.59	4.55	12.53	2.28E-02	2.24		24.17
Unit 3	20.20	15.90	1.04	5.46E-02	4.77		41.96
Units 1 & 2 cooling & service water towers						4.4	4.40
Unit 3 cooling tower						1.95	1.95
Total	27.21	25.04	26.22	1.17E-01	9.28	6.35	94.68

PSCo – Comanche Actual Emissions

Emission Unit	Data Year*	Emissions (tons/yr)						
		PM	PM ₁₀	SO ₂	NO _x	CO	VOC	HAPs**
Unit 1	2010	80.40	73.90	701.00	1,338.70	320.60	39.10	4.04
Unit 2	2010	44.90	41.30	599.00	1,474.00	270.30	31.30	3.21
Unit 3	2010	341.60	310.50	1,269.00	1,064.40	523.10	54.00	5.66
2 cooling water and 2 service water towers (96PB153-2)	2010	3.00	3.00				3.50	3.5
Unit 3 cooling water tower	PTE	11.16	2.68				2.35	2.35
Coal handling - point source	2010	5.08	3.35					
Coal handling - fugitive	2010	7.75	1.82					
Waste ash handling - point source	2010	0.88	0.87					
Waste ash handling - fugitive	2010	7.22	2.43					
Recycle ash handling	2008	1.64	1.64					
Lime handling	2008	0.64	0.64					
Sorbent handling	2009	2.00E-04	2.00E-04					
Haul roads	2010	7.40	1.90					
Emergency generator	PTE	0.10	0.10	0.10	4.20	1.70	0.11	
Total		511.77	444.13	2,569.10	3,881.30	1,115.70	130.36	18.76

*Data year indicates the year for which actual emissions are reported. If PTE is indicated in this field, emissions indicated are requested (i.e. permit limits)

**Actual HAPs are based on those HAPs reported on APENS (emissions above the reporting threshold).

Unit 3 Opacity Streamlining Grid

Reqmt Source	Normal	Start-up	Shutdown	Malfunction	Fire Building	Cleaning of Fire Boxes	Soot Blowing	Process Modifications	Adjustment of Control Equipment
Reg 1 Sections II.A.1 & 4	20%	30% with one 6 minute interval in excess of 30% per hour	20%	20 %	30% with one 6 minute interval in excess of 30% per hour	30% with one 6 minute interval in excess of 30% per hour	30% with one 6 minute interval in excess of 30% per hour	30 % with one 6 minute interval in excess of 30% per hour	30% with one 6 minute interval in excess of 30% per hour
Reg 6, Part B, Section II.C.3 - State Only	20%	No standard ¹	No standard ¹	No standard ¹	20%	20%	20%	20%	20%
NSPS Subpart Da (40 CFR § 60.42a(b))	20% with one 6 minute interval of 27% per hour	No standard ¹	No standard ¹	No standard ¹	20% with one 6 minute interval of 27% per hour	20% with one 6 minute interval of 27% per hour	20% with one 6 minute interval of 27% per hour	20% with one 6 minute interval of 27% per hour	20 % with one 6 minute interval of 27% per hour
BACT Limits (Colorado Construction Permit 04PB1015)	10%	30% with one 6 minute interval in excess of 30% per hour	20%	10%	10%	10%	10%	10%	10%

¹Although the opacity standards are not applicable during start-up, shutdown and malfunction 40 CFR § 60.7(c) (2) requires the source to report each period of excess emissions that occurs during startups, shutdowns, and malfunctions, the nature of the malfunction and the corrective action taken or preventative measures adopted.

* Shaded regions are the most stringent requirements

Unit 3 Particulate Matter Streamlining Grid

Requirement Source	Normal	Start-up	Shutdown	Malfunction
Reg 1 Sections II.A.1 & 4	0.1 lb/MMBtu	0.1 lb/MMBtu	0.1 lb/MMBtu	0.1 lb/MMBtu
NSPS Subpart Da (40 CFR § 60.42a(c)(2)) ¹	0.015 lb/MMBtu	No standard ²	No standard ²	No standard ²
BACT Limit (Colorado Construction Permit 04PB1015) ¹	0.0120 lb/MMBtu	0.0120 lb/MMBtu	0.0120 lb/MMBtu	0.0120 lb/MMBtu

¹For both the NSPS and BACT limit, the averaging time is based on the average of three test runs (each test is 2-hr duration). However, once the source is required to use the PM CEMS, the averaging time will be based on 24-hr block average (for NSPS Da) or a 24-hr rolling average (BACT limit).

²According to 40 CFR Part 60 Subpart Da § 60.48a(c), the particulate matter emission limits apply at all times except during periods of startup, shutdown and malfunction.

* Shaded regions are the most stringent requirements